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# Proposed audit and accounting guide : audits of entities with oil and gas producing activities ;Audits of entities with oil and gas producing activities; Exposure draft (American Institute of Certified Public Accountants), 1984, April 25

American Institute of Certified Public Accountants. Oil and Gas Committee

# EXPOSURE DRAFT

# PROPOSED AUDIT AND ACCOUNTING GUIDE

# AUDITS OF ENTITIES WITH OIL AND GAS PRODUCING ACTIVITIES

APRIL 25, 1984

Prepared by the Oil and Gas Committee of the
American Institute of Certified Public Accountants

Comments should be received by July 24, 1984 and addressed to
W. Wade Gafford, Auditing Standards Division, File 3730
AICPA, 1211 Avenue of the Americas, New York, New York 10036–8775

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**AICPA**

**American Institute of Certified Public Accountants**
1211 Avenue of the Americas, New York, New York 10036 (212) 575-6200

April 25, 1984

Accompanying this letter is an exposure draft of a proposed AICPA audit and accounting guide, Audits of Entities With Oil and Gas Producing Activities. A summary of the proposed guide accompanies this letter.

The proposed guide discusses those aspects of accounting and auditing that are unique to the oil and gas producing industry. It was developed to assist independent auditors in their examinations of financial statements of entities with oil and gas producing activities. At the time the proposed guide went into publication, the SEC was considering changes to its full cost rules that would affect the section on lease brokerage activities. If the SEC amends its rules, the guide will be changed accordingly.

Comments or suggestions on any aspect of this exposure draft will be appreciated. Commentators on the proposed guide are specifically requested to give particular attention to whether any accounting principle for take-or-pay contracts other than that described in paragraph 280 is generally accepted. The committee's consideration of responses will be helped if the comments refer to specific paragraph numbers and include reasons for any suggestions or comments.

In developing guidance, the AICPA Auditing Standards Division considers the relationship between the cost imposed and the benefits reasonably expected to be derived from audits. It also considers differences that the auditor may encounter in the audit of the financial statements of small businesses and, when appropriate, makes special provisions to meet those needs. Thus, the division would particularly appreciate comments on those matters.

Responses should be sent to the AICPA Auditing Standards Division, File 3730, in time to be received by July 24, 1984.

Written comments on the exposure draft will become part of the public record of the AICPA Auditing Standards Division and will be available for public inspection at the offices of the American Institute of Certified Public Accountants after August 7, 1984, for one year.

Sincerely,

Peter L. Jensen

Peter L. Jensen
Chairman
Oil and Gas Committee

Don Pallais

Don Pallais
Director, Audit and Accounting Guides

## SUMMARY

This proposed audit and accounting guide describes operations and accounting practices that are unique to the production of oil and gas as well as matters that are unique to the audit of financial statements of entities with oil and gas producing activities. Descriptions of accounting practices were limited to those that were essential to understanding typical audit objectives and procedures unique to the industry.

Specifically, the proposed guide discusses income taxes, internal control, and audit considerations in the oil and gas producing industry. The proposed guide also discusses the business activities of the oil and gas producing industry—acquisition of mineral properties, exploration, drilling and development, oil and gas reserves, and production. The committee specifically asks for comments on the accounting for take-or-pay contracts as discussed in paragraph 280.

The exposure draft has been sent to—

- State society and chapter presidents, directors, and committee chairmen.
- Organizations concerned with regulatory, supervisory, or other public disclosure of financial activities.
- Individuals and firms identified as having an interest in oil and gas accounting and auditing.
- Persons who have requested copies.

## INTRODUCTION

This guide has been prepared to assist the independent auditor in examining and reporting on financial statements of entities with oil and gas producing activities by describing relevant matters unique to the industry.

Generally accepted auditing standards and accounting principles are applicable in general to the oil and gas producing industry. The general application of these standards and principles is not discussed herein; rather, this guide focuses on the special problems inherent in auditing and reporting on the financial statements of an entity with oil and gas producing activities.

The guide provides information regarding statutory rules and regulations applicable to the industry. Also included are illustrations of the form and content of financial statements for entities with oil and gas producing activities. Rules and regulations, as well as applicable authoritative accounting and auditing pronouncements, are subject to change and revision. Therefore, the auditor should keep abreast of developments affecting these items.

The guide contains certain suggested auditing procedures, but detailed internal accounting control questionnaires and audit programs are not included. The nature, timing, and extent of auditing procedures are a matter of professional judgment and will vary depending on the size, organizational structure, existing system of internal accounting control, and other factors in a particular engagement.

The accounting principles described in this guide are limited to the successful efforts method specified by Statement of Financial Accounting Standards No. 19 and the full cost method specified by the Securities and Exchange Commission (SEC) in Regulation S-X. It should be recognized that hybrids of both of these methods are commonly referred to by those names and often are considered to be within the framework of generally accepted accounting principles for companies not reporting to the SEC. FASB Statement No. 25 suspended the effective date of requiring the successful efforts method of accounting as specified by FASB Statement No. 19. However, it states that for purposes of applying paragraph 16 of APB Opinion No. 20, Accounting Changes, successful efforts is the preferable method of accounting for oil and gas producing activities; therefore, no justification for a change to the successful efforts method is necessary nor is a preferability letter for such a change required by the SEC for its registrants. Any change to the full cost method must be justified as being preferable in the circumstances and a preferability letter describing those circumstances must be filed with the SEC by its registrants.

The guide has not been expanded to include other practices followed by some private companies.

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# CHAPTER 1

# OVERVIEW OF THE OIL AND GAS INDUSTRY

## THE INDUSTRY'S HISTORY

1. To gain an understanding of oil and gas producing activities, a brief review of the history of the industry and oil and gas accounting is helpful. The following discussion is intended to be basic in nature. Additional references are included in the bibliography section of this guide. The interested reader is urged to supplement the reading of this guide with some of the other available sources.

2. The first commercial oil drilling venture was in 1859 near Titusville, Pennsylvania. A steam-powered, cable-tool drilling rig was used to drill a fifty-nine-foot well, which yielded five barrels of oil per day. This well set off a boom of sorts, and the cable-tool rig, which at that time was revolutionary, was used to drill other wells in the area. Because of the dramatic increase in supply, oil sold for about ter cents a barrel.

3. In the 1850s and early 1860s, oil was chiefly used for lamp fuel. The Industrial Revolution and the Civil War greatly increased the uses and therefore the demand for oil, such that annual production in 1870 exceeded twenty-five million barrels. Early transportation of crude oil, however, was cumbersome, involving wooden barrels (each with a capacity of forty-two gallons—the present measurement of a barrel of crude oil), horse-drawn wagons, river barges, and the railroads. The first pipeline, completed in the 1860s, was made of wood and was less than a thousand feet long.

4. One of the first men to rise to power in this infant industry was John D. Rockefeller. In 1870, Rockefeller merged his company with four others to form the Standard Oil Company. During the 1880s, Standard Oil controlled approximately 90 percent of the refining industry in the United States. Standard's market dominance eventually led to its dissolution in 1911-1915 because of federal and state antitrust legislation.

5. The growing number of automobiles steadily increased the demand for oil. Because of a feared domestic shortage, the industry was encouraged by the U.S. government to increase foreign exploration. In the 1920s, exploration in the Middle East, South America, Africa, and the Far East had begun. The east Texas oil field discovery of 1930 created an oil surplus that caused companies to cut back foreign operations. During and after World War II, however, demand had again increased, and enormous capital investments were made to develop the Persian Gulf area. This period also saw an increased use of natural gas, facilitated by improved transportation systems, and the growth of the petrochemical industry (plastics and synthetics).

6. The oil and gas industry has gone through many changes in the past twenty years. The Arab oil embargo of 1973 focused public attention and criticism on the industry, partly because of its effect on previously stable prices. In 1973, before the embargo, the average barrel of crude oil sold for about $3. By

the early 1980s, the price for a barrel of oil ranged from $30 to $40 and sometimes higher, representing an approximate 1000 percent increase in less than ten years. The effects of this increase were further complicated by price controls that designated different grades of oil and a complex pricing structure. As a result of price controls, producing companies grew reluctant to explore and drill. This reluctance may have stemmed from the ironic fact that, due to price controls, a barrel of domestically produced oil often had a sales price significantly less than the price of imported oil. By 1977, nearly half of the oil used by the United States was imported. In 1979, the government announced "phased decontrol" of oil prices on a schedule that would have freed all crude prices by October 1981. However, in January 1981, all price controls on crude oil were immediately lifted. Natural gas prices continued to be subject to controls, as required by the Natural Gas Policy Act of 1978, but were scheduled for partial deregulation. Burdened with heavy government regulation and fierce competition, the oil and gas industry presents complex accounting and auditing problems.

## TYPES AND SIZES OF COMPANIES IN THE INDUSTRY

7. Companies engaged in oil and gas exploration and production are characterized by a wide diversity in type and size, of which most are primarily dependent on their success in exploring for and developing oil and gas reserves. Companies in the industry range from the largest corporations in the world to very small companies or proprietorships with limited sales and resources.

8. The organization of oil and gas companies varies depending on size and diversity of activities. Oil and gas producers are usually classified as independent or integrated companies. A fully integrated company produces oil and gas and operates refineries, pipelines, and wholesale and retail outlets. Some companies are only partially integrated.

9. Independent exploration and production companies generally do not refine products or engage in marketing activities. They limit their activities to exploration, development, and production.

10. Discussions in this guide will concentrate on the oil and gas exploration and production activities of both independent and integrated oil and gas operations. These activities include acquisition of mineral properties, exploration, drilling and development, and production.

## OWNERSHIP INTERESTS AND OPERATIONS

11. Characteristics relatively unique to oil and gas operations are the normal existence of multiple ownerships of individual properties and the varying types of ownership interests. The variety of ownership interests has developed in response to the need to share risks, to take advantage of tax opportunities, and to raise the large amounts of capital necessary in the industry. The principal types of ownership or economic interests encountered in the industry are discussed below. However, because of the easily divisible nature of oil and gas operations, variations of these will be encountered.

## Types of Interests

12. Mineral Interest. The complete ownership of the minerals in place.

13. Working Interest. The interest in the oil and gas in place that bears most or all of the cost of development and operation of the property. Mineral interest revenues minus the royalty interest equals the working interest share of revenues. The working interest is also referred to as an operating interest.

14. Royalty Interest. The portion of the mineral interest retained by the lessor. It entitles the royalty interest owner to a fractional amount of the production from the property, in kind or in value, less applicable severance and windfall profit taxes. Occasionally, the royalty interest may bear certain specific costs.

15. Overriding Royalty. A royalty interest that is created out of the working interest. Its term is coextensive with that of the working interest from which it was created.

16. Net Profits Interest. An interest in production created from the working interest and measured by a certain percentage of the net profits (as defined in the contract) from the operation of the property.

## Origination of Interests

17. Retained Interest. An interest that arises when the working interest owner transfers the basic rights and responsibilities for developing and operating the property to another party and retains a special nonoperating interest created by the conveyance contract.

18. Carved Out Interest. An interest created when the operator retains the basic working interest but grants to another entity special nonoperating rights and obligations.

## Joint Interest Operations

19. Operating Agreements. Joint interest operations result from an agreement among two or more working interest owners whereby one party is designated as the operator for the development or operation of the property on behalf of all parties to the agreement. These arrangements are designed to accomplish the objectives of sharing risk, obtaining capital, maximizing efficiency of development and operations, and enhancing the recovery of reserves and conserving reservoir pressures.

20. Joint interest operations are governed by complex operating agreements that spell out the rights, duties, and obligations of each party. A significant part of the agreement is the accounting procedure section, which establishes the basis for charges and credits to the operator and the nonoperating parties and provides for billings, advance of funds, payment schedules, audits, and other general provisions of the arrangement. The accounting provisions in joint operating agreements usually follow a model provision devised by the Council of

Petroleum Accountants Societies (COPAS). Although the lease is usually considered the accounting unit, many costs cannot be directly identified with a particular lease. Such costs are usually categorized as indirect expenses and are recovered by allocating overhead to leases on some reasonable basis. These costs include service unit costs and certain types of overhead.

21. The operator bills the nonoperators, usually at the end of each month, for their share of the expenditures for the month. The billing is referred to as a joint interest billing (JIB). The operator may also make a cash call at the beginning of each month for the nonoperator's share of anticipated expenditures to be incurred during the month. In some cases, the operator may also collect revenues from production and distribute the proceeds to the various ownership interests, although in many cases the purchaser will pay the various interests directly based on the division order.

22. Most large oil and gas companies, and many smaller companies, act as operators on a number of the oil and gas properties in which they have an interest. It should be recognized, however, that nearly all companies will be nonoperators with respect to a significant portion of their properties. In addition, the extent to which nonoperators take an active role in the operation of properties varies widely in practice. In many instances, the nonoperator will maintain full accountability for activities on the properties, including advance authorization of capital expenditures through the authorization for expenditure AFE process and review and approval of revenue and expense transactions. In other instances, nonoperators may rely almost entirely on the operator for recording transactions and maintaining accountability, receiving only a summary report of activity. The degree of actual involvement in practice may fall anywhere within this range.

23. Joint Interest Audits. The accounting procedure section usually contains a provision that establishes the timing of the auditing of the operator's records by the nonoperating parties. Under some of the accounting procedures, the nonoperators may audit the operator's accounting records within two years after the end of the period to be audited. If such an option is not exercised, or if an exception is not granted in advance, the nonoperator would be precluded from conducting a subsequent audit and all transactions billed would be considered correct.

24. In some of the older agreements, provisions have existed whereby the nonoperator was permitted much less time to conduct an audit; for example, a six-month constraint was not unusual.

25. Joint interest audits are normally conducted by the nonoperator's internal auditors or by independent auditors hired by the nonoperator. The purpose, and therefore the scope, of joint interest audits is significantly different from an examination of financial statements in accordance with generally accepted auditing standards. Such audits are beyond the scope of this guide.

26. Division Orders. Contractual agreements among the parties determine ownership interests, and rarely are two contracts exactly the same. In almost every case there will be at least two recipients of production proceeds: the working interest owner and the royalty owner. Thus, a division-of-interest order (or simply division order) is prepared to indicate the proper distribution of production proceeds.

27. A regular division order is a contract between the purchaser of production and all the various owners of interests in the property. This contract includes the legal description of the property; the owners of interests in the property; the interest owned by each; and the terms of purchase, including provisions dealing with passage of title, price, measurement, production taxes, and related items. The operator of the property circulates the division order to the various owners of interest. Each owner, by signing the division order, guarantees his ownership to be as stated, authorizes the purchaser to receive production from the property and to make payment to the owners in proportion to their respective interests, and agrees to all other provisions of the division order. Sometimes the operator receives the full payment from the purchaser and makes the distribution to the other owners.

28. In the event that an owner of interest is unknown or cannot be located and his signature cannot be secured on the division order, the revenue applicable to that interest is held in suspense. In a similar manner, revenue is held in suspense pending receipt of proof of title or title opinion, execution of the division order, or litigation to resolve a dispute over ownership of an interest.

## SOURCES OF CAPITAL

29. Oil and gas producing companies require enormous amounts of capital, especially in their exploration and development activities. As in most industries, the traditional sources of capital are internal financing, external financing, and equity financing. However, the various and sometimes unique adaptations in the oil and gas industry warrant review.

30. In the past, oil and gas companies, especially those that were large and financially strong, had been able to fund a large amount of their exploration and development activities with internally generated funds (earnings). Increased competition among companies for exploration rights to undeveloped properties and rising acquisition and development costs have resulted in companies turning more frequently to other sources of funds.

### Joint Interests

31. Companies often enter into arrangements with others as a means of raising or sharing capital. This can be done by creating joint ventures or partnerships, but is often accomplished by transferring a portion of the working interest to other parties, as discussed more thoroughly under "Conveyances" in chapter 2. Depending on the attractiveness of the property and the owner's willingness to dilute his interest, a portion of the development costs of a property may be financed in this manner. An example of a common deal in the industry is a "third for a quarter," in which the purchaser agrees to assume a third of the exploration or development costs in exchange for a fourth of the working interest in the property.

## Limited Partnerships

32. It is common for oil and gas operators to organize limited partnerships. These partnerships are commonly called "oil and gas funds" or "oil and gas programs." Limited partnerships are organized by a sponsor who sells interests in the partnership to private investors and then acts as the general partner when the partnership has been organized. Limited partnerships are usually structured to maximize the tax deductions passed through to the limited partners. The limited partners are usually liable only for the amount of their contribution to the partnership. The general partner normally has unlimited liability for the debts and obligations above the limited partners' capital; however, the general partner has full control over the partnership's operations.

33. The partnerships typically are either drilling funds or production funds. Drilling funds are organized to finance exploration of new prospects, while production funds are invested only in properties known to contain oil or gas.

34. The limited partnership is governed by the partnership agreement, which explains the rights and obligations of the partners. The partnership agreement dictates the method of allocating revenues and expenses between the general and limited partner interests. The basic allocation methods are functional allocation, reversionary interest, promoted interest, and carried interest.

35. Functional allocation usually provides for the tax-deductible expenses to be paid with the limited partners' contribution and allocated to them. Capital expenditures such as leasehold costs and equipment are paid with the general partners' contribution. Revenue sharing is based on a predetermined percentage ratio between the general and limited partners. This method normally achieves the fastest deduction of costs for the limited partners.

36. Under a reversionary interest allocation, the limited partners' contribution is used to pay the largest percentage of the partnership expenses, and the limited partners receive a high percentage of the revenues until they recover their initial capital contributions. After the limited partners recover their initial investment, the allocation reverts to another percentage ratio assigning a larger portion of revenues and expenses to the general partner interest.

37. In a promoted interest program, the general partner pays a specified percentage of all costs and receives a larger percentage of net revenues.

38. In a carried interest program, the general partner pays a specified percentage of operating costs and receives a specified percentage (often larger) of revenues but does not bear any capital costs.

39. Aside from the differences in the equity section of the financial statements and the allocation of revenues and costs between the general and limited partners, which is dictated by the partnership agreement, the accounting for and the auditing of an oil and gas limited partnership are basically the same as for any other oil and gas producer. However, financial statements are often prepared on either the income tax or cash basis, except for those of public limited partnerships, which are required to be prepared on the basis of generally accepted accounting principles.

## Other Sources of Capital

40. Production payment transactions, whereby a lender advances funds to be repaid from future production, are quite common. Short-term as well as long-term financing from banks often takes the form of production loans, secured by specific, producing mineral properties.

41. The oil and gas company may choose to enter the conventional equity market to secure funds. The company may offer its securities either in a private placement primarily to institutional investors or in a public offering. Offerings, including those of limited partnerships, depending on the size, number of investors, and geographical range of solicitation, may require registration with state and federal agencies.

42. While the above alternatives are not necessarily exhaustive, the auditor should be aware of the potential implications of the different forms of financing.

## ACCOUNTING FOR OIL AND GAS PRODUCING ACTIVITIES

43. The two primary accounting methods followed by oil and gas producers are the successful efforts method and the full cost method. Successful efforts accounting essentially provides for capitalizing only the costs directly related to proved properties and amortizing those costs over the life of the properties.

44. Prior to the mid-1950s, most oil and gas companies used the successful efforts accounting method or some variation thereof. In the mid-1950s, a form of the full cost method of accounting was introduced.

45. The full cost concept became popular with small, newly formed companies. It allowed them to defer their early costs until successful exploration produced offsetting revenue. By 1970, almost half of the public oil and gas producing companies were using a form of the full cost method.

46. Full cost accounting generally provides for capitalizing, within a cost center, all costs incurred in exploring for, acquiring, and developing oil and gas reserves, regardless of whether or not the results of specific costs are successful. This is based on the premise that the costs of unsuccessful exploration efforts are necessary for the discovery of reserves even though such expenditures are made with the knowledge that specific efforts may not result in the discovery of reserves. Thus, all costs incurred in acquiring mineral rights, in drilling, and in exploration activities, along with all carrying costs of non-producing properties in the cost center, are treated as the cost of reserves in that center. The costs capitalized in a cost center are then amortized and charged to expense as the mineral reserves in that cost center are produced.

47. Under the full cost method, the cost center is used to "pool" costs to be later matched with revenues generated from the cost center's operations. Under the broadest concept, the company's entire worldwide oil and gas operations would be treated as a single cost center. Most companies, however, consider the continent or the individual country a cost center, and the SEC accounting rules specify the size of cost centers to be an individual country.

48. In 1969, the American Institute of Certified Public Accountants (AICPA) published Accounting Research Study (ARS) No. 11, which called for the elimination of the full cost method and recommended that the successful efforts method be the only acceptable method. The Accounting Principles Board (APB) appointed a committee to develop an authoritative opinion on financial accounting and reporting for the oil and gas industry; however, the APB was terminated in 1973 before the committee completed its charge.

49. In December 1977, the Financial Accounting Standards Board (FASB) issued Statement No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies. The statement required a form of successful efforts accounting as the uniform method for all enterprises engaged in oil and gas producing activities.

50. In summary, successful efforts accounting per FASB Statement No. 19 provides that—

- Geological and geophysical costs, costs of carrying and retaining undeveloped properties, and dry hole and bottom hole contributions should be charged to expense when incurred.

- The costs of drilling exploratory wells and exploratory-type stratigraphic test wells should be capitalized pending determination of whether the well has found proved reserves. The costs of unsuccessful wells should be charged to expense.

- Acquisition costs should be capitalized initially; however, losses should be recognized if the values of unproved properties are determined to be impaired on the basis of a required periodic assessment.

- Production costs together with the amortization of the capitalized acquisition, exploration, and development costs should become the cost of oil and gas produced.

- Capitalized acquisition costs should be amortized on the unit-of-production method using total proved oil and gas reserves. Capitalized exploration and development costs should be amortized on the unit-of-production method using proved developed oil and gas reserves.

51. Substantial protest followed the issuance of FASB Statement No. 19, such that the Securities and Exchange Commission (SEC) called for public hearings before adopting the statement as the authoritative standard of accounting and reporting for oil and gas producing companies filing reports with the SEC. Because of the strong opposition voiced at those hearings, the SEC issued Accounting Series Release (ASR) No. 253, Adoption of Requirements for Financial Accounting and Reporting Practices for Oil and Gas Producing Activities, which—

- Adopted the form of successful efforts accounting and the disclosures prescribed by FASB Statement No. 19.

- Indicated the SEC's intention to develop a form of the full cost accounting method as an alternative acceptable for SEC reporting purposes (ASR No. 258).

- Concluded that both the full cost and successful efforts methods of accounting, based on historical costs, fail to provide sufficient information on the financial position and operating results of oil and gas producing companies and, accordingly, that steps should be taken to develop an accounting method based on a valuation of proved oil and gas reserves (The SEC later decided that the valuation accounting it proposed, reserve recognition accounting (RRA), was no longer considered to be a potential method of accounting in the primary financial statements of oil and gas producers. The SEC also announced its support of an undertaking by the FASB to develop a comprehensive disclosure package for those engaged in oil and gas producing activities.)

- Adopted rules that require financial statement disclosure of certain financial and operating data regardless of the method of accounting followed.

In ASR Nos. 257 and 258, the SEC released its final rules for successful efforts and full cost accounting. At that point, companies under SEC jurisdiction could follow either the full cost method prescribed in ASR No. 258 or the successful efforts method prescribed in ASR No. 253, as modified by ASR No. 257, a method identical to that contained in FASB Statement No. 19.

52. In response to the SEC's issuance of ASR No. 253, the FASB issued Statement No. 25, Suspension of Certain Accounting Requirements for Oil and Gas Producing Companies. This statement suspended, for an indefinite period of time, most of the provisions of FASB Statement No. 19. However, some provisions of FASB Statement No. 19, including deferred income taxes and some aspects of property conveyances and disclosure requirements, were retained and became effective.[1] Thus, companies that report to the SEC may follow either the full cost accounting method prescribed by ASR No. 258 or the successful efforts method prescribed by ASR No. 253 as modified by ASR No. 257 (a method identical to that contained in FASB Statement No. 19). For nonpublic companies there is no prescribed method of accounting for costs incurred in oil and gas exploration or for amortization of those capitalized costs.

53. In November 1982, the FASB issued Statement No. 69, Disclosures about Oil and Gas Producing Activities. This statement amended FASB Statement No. 19 by establishing disclosures about oil and gas producing activities to be made for publicly traded enterprises when presenting a complete set of annual financial statements. The SEC, in Financial Reporting Release No. 9, generally adopted these disclosure standards. In summary, FASB Statement No. 69 provides for the following disclosures for public companies as supplementary information:

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[1]FASB Statement No. 25 also states that for purposes of applying paragraph 16 of APB Opinion No. 20, Accounting Changes, successful efforts is the preferable method of accounting for oil and gas producing activities; therefore, no justification for a change to the successful efforts method is necessary nor is a preferability letter for such a change required by the SEC for its registrants. Any change to the full cost method must be justified as being preferable in the circumstances and a preferability letter describing those circumstances must be filed with the SEC for its registrants. The SEC's position on preferability letters for accounting changes to or from the successful efforts or full cost methods is described in ASR No. 300.

- Net quantities of proved reserves and proved developed reserves of oil and gas as of the beginning and end of the year, with details of changes in proved reserves during the year

- Capitalized costs relating to oil and gas producing activities and the related depreciation, depletion, amortization, and valuation allowances as of the end of the year

- Costs incurred in oil and gas property acquisition, exploration, and development activities during the year

- Details of the results of operations for oil and gas producing activities during the year

- Standardized measure of discounted future net cash flows relating to proved oil and gas reserve quantities as of the end of the year, with details of changes in the standardized measure during the year

54. For purposes of this guide, "successful efforts" will refer to the accounting method specified in FASB Statement No. 19 and "full cost" will refer to the accounting specified in Regulation S-X of the SEC. It should be recognized that hybrids of both of these methods are commonly referred to by those names and often are considered to be within the framework of generally accepted accounting principles for companies not reporting to the SEC.

55. In addition to accounting methods included within generally accepted accounting principles, income tax laws and regulations have a major effect on both accounting and economic decisions of oil and gas companies. There are many significant differences between income tax and either of the principal accounting methods, including the ability to charge all intangible drilling costs to expense for income tax purposes. The auditor should have an understanding of the more common differences, which are discussed in chapter 3.

# CHAPTER 2

## BUSINESS ACTIVITIES OF THE OIL AND GAS PRODUCING INDUSTRY

### ACQUISITION OF MINERAL PROPERTIES

56. In the oil and gas industry, rights to drill wells and produce minerals found are generally obtained through leasing transactions. Although the operator may acquire the fee interest in the property (outright ownership of both minerals and surface), this is not customary today. The operator usually obtains a lease from a landowner, either through the in-house landman or from an independent lease broker. The landman or broker researches the public records to verify the legal owner of the mineral interest in the property and may obtain legal title opinions, although in many instances the title work will not be performed until shortly before drilling commences. The landman or broker then negotiates the lease terms with the landowner. Leases on state-owned properties are normally awarded through a bidding process, with leases granted to the highest bidder. Leases on federally owned properties located offshore or on known geological structures, and certain other properties, are also awarded by bidding. Leases on most federally owned properties located onshore are awarded through lease application systems with a standard fee.

57. As discussed under "Exploration" in this chapter, exploration activities may take place prior to acquisition of the mineral rights.

#### The Lease

58. The most important and most commonly found provisions in oil and gas (or minerals) leases are outlined below, but it is important that oil and gas leases be read carefully by the auditor to obtain an understanding of the principal provisions. Although the basic provisions in leases are similar, each lease may contain unique provisions.[2] These basic provisions are discussed below.

59. Lease Bonus. The lease bonus is the cash or other consideration paid to the lessor by the lessee in return for the lessor's granting the lessee rights to explore for minerals, drill wells, and produce any minerals found. The bonus is computed on a per-acre basis and may range from a few dollars per acre in wildcat locations to thousands of dollars per acre for locations near producing properties. In negotiated leases, the full amount of the bonus may not be specified in the lease agreement.

60. Primary Term. The maximum period of time allowed for the lessee to commence drilling a well is referred to as the primary term, which is normally three to ten years.

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[2]A standard lease agreement, prepared by the American Association of Petroleum Landmen, is often adapted to fit particular circumstances.

61. <u>Drilling Obligation</u>. The lease will generally stipulate that either drilling operations begin within a specified period (usually one year) or that the lessee make a specified payment (delay rental) to the lessor. In succeeding years, the same drilling obligation exists but can be deferred (and the lease retained) by making the specified payment; however, no provision is made for the extension of the lease by payment of rent beyond the primary term.

62. <u>Delay Rentals</u>. The payment made to defer drilling activities for an additional year is called a delay rental. The amount of the delay rental is normally much smaller than the lease bonus.

63. <u>Royalty Provisions</u>. The lessor retains a royalty interest in the minerals. This interest entitles the lessor to receive free and clear of all costs a specified portion of the oil and gas produced, or a specified portion of the value of such production, except for the related state severance or production taxes, the windfall profit tax, and certain costs necessary to get the product into a salable condition.

64. <u>Production Holds Lease</u>. Once a successful well has been drilled and commercial production is obtained, the lease usually remains in effect for as long as there is production without extended and indefinite interruption. If production ceases, the operator must act in good faith to resume the extraction of oil or gas within a reasonable time (specified in the lease contract).

65. <u>Right to Assign Interest</u>. The lease contract grants each party the right to assign, without approval of the other party, any part or all of its rights and obligations.

66. <u>Fixed or Mandatory Rentals</u>. The contract may provide for rental payments that cannot be avoided even though the property is abandoned or drilling has begun. In effect, these payments are deferred bonuses paid on an installment basis.

67. <u>Shut-in Royalties</u>. Most lease contracts provide for shut-in royalties, which represent payments by the operator to the royalty owner if a successful well has been drilled but production has not begun within a specified time. Shut-ins frequently occur on properties containing gas and may be due to absence of a market, lack of transportation, necessity to obtain permission from a governmental unit, or for other reasons. Shut-in payments may or may not be recoverable by the operator out of future amounts accruing to the royalty owner.

68. <u>Offset Clause</u>. A common provision called an offset clause requires an operator to drill such offset wells to prevent drainage of oil or gas to another tract as a prudent operator would drill under similar circumstances.

69. <u>Compensatory Royalties</u>. Payments known as compensatory royalties are made by oil companies to royalty owners as compensation for the latter's loss of income during periods when the company has not fulfilled its obligation to drill.

70. <u>Guaranteed or Minimum Royalties</u>. If leases are acquired on property having a high probability of being productive, the mineral owner may be able to negotiate a provision in the lease requiring the lessee to guarantee the mineral

owner a specified minimum royalty payment each month or each year. If the royalty owner's share of net proceeds from production is less than the specified amount, the lessee must pay the difference. Guaranteed payments may be nonrecoverable or may be recoverable out of future royalties accruing to the royalty owner.

Other Considerations

71. Almost all transactions related to oil and gas activities have their foundations in the lease contract.

72. Oil and gas producers may also acquire interests in properties that have already been leased, and perhaps drilled and developed by others. This is usually accomplished by assigning all the rights and obligations of the original lessee through a sale or by acquiring the operating interest subject to a non-operating interest retained by the original lessee (sublease). Typically, the assignment contract specifies the agreed-on value of well and lease equipment, and the balance of purchase price is deemed to be applicable to the mineral rights obtained.

73. When a fee interest in property is acquired, the transaction is similar to a standard real estate transaction.

74. After mineral rights have been acquired through purchase or lease, several years may elapse before drilling begins. Economic or market conditions may delay development. During that period, the holder of the rights may be required to pay ad valorem taxes and incur other carrying costs in addition to possible delay rentals or minimum royalty payments.

75. The company will usually maintain a prospect file or a lease file, or both, for each property. These files generally include, as a minimum, a copy of the lease, the survey or other legal description of the property, and the title opinions. As the prospect develops, the lease file will include additional documents such as authorizations for expenditures (AFEs), division orders, purchase contracts (if applicable), operating agreements, and producer-status certifications.

76. The lease file system should have a feature to keep abreast of the timing of delay rental payments and reassignment obligations. If delay rental payments are not made when due, the lease contract expires. It is obviously important that lease rentals be paid on properties that the lessee does not wish to surrender. Customarily, the lessee may avoid all obligations and give up all rights and responsibilities by simply failing to pay rentals when due, or the lessee may terminate the contract at any other time by executing a formal lease surrender or a quit claim deed.

77. If the lessee wishes to retain a property whose primary term is about to expire but on which drilling has not yet begun, an extension of the original lease may be agreed to by both parties upon an additional payment by the lessee, or a top lease (a new lease contract on the same property) may be executed, usually involving an additional bonus payment by the lessee. A top lease may also be taken by a third party, in expectation of the expiration of the existing lease.

## Accounting for Acquisition Costs

78. Successful Efforts. Under the successful efforts method, costs associated with the acquisition of leases are capitalized when incurred. These consist of costs incurred in obtaining a mineral interest in a property, such as the costs of lease bonuses and options to lease, brokers' fees, recording fees, legal costs, and other similar costs in acquiring property interests.

79. Unproved properties are assessed periodically to determine whether they have been impaired under successful efforts accounting. A property might be considered impaired if, for example, a dry hole has been drilled on a portion of it or in close proximity to it and the company has no intention of further drilling on the property. Also, as the expiration of the lease term approaches, if the company has not begun drilling on the property or nearby properties, the possibility of partial or total impairment of the property may increase. Impairment on individually significant unproved properties is assessed on a property-by-property basis. If a property is found to be impaired, an impairment allowance is provided and a loss is recognized in the income statement.

80. Unproved properties whose costs are individually insignificant may be amortized in the aggregate or by groups, on the basis of the experience of the company in similar situations and considering such factors as the primary lease terms, the average holding period of unproved properties, and the relative proportion of such properties on which proved reserves have been found in the past.

81. Properties are classified as unproved until proved reserves are discovered on the property. If a property being reclassified as proved has previously been impaired on an individual basis and a valuation allowance has been established, the net amount (acquisition cost minus valuation allowance) is reclassified. If a valuation allowance has been provided on the property on a group basis, the gross acquisition cost is reclassified as proved.

82. If an unproved property is surrendered or expires, the cost of the property is charged against the impairment allowance to the extent it has been provided. Any excess basis is charged to loss.

83. Full Cost. Under the full cost method, all costs associated with the acquisition of properties are capitalized within the appropriate cost center. Prior to 1983, all capitalized costs were included in the full cost pool and became part of the amortizable base, although in certain circumstances, the cost of unusually significant investments in unproved properties and major development projects could be excluded from costs to be amortized. Effective with the SEC's adoption of Release No. FR-14 in 1983, all costs directly associated with the acquisition and evaluation of unproved properties may be excluded from the amortization computation until it is determined whether or not proved reserves can be assigned to the properties. The computation of depreciation, depletion, and amortization (DD&A) is further discussed under "Accounting for Production" in this chapter.

84. Full cost accounting requires that properties excluded from the amortization computation be assessed at least annually to ascertain whether impairment has occurred. Unevaluated properties whose costs are individually significant are assessed individually. When it is not practicable to individ-

ually assess the amount of impairment of properties for which costs are not individually significant, such properties may be grouped for purposes of assessing impairment. The amount of impairment assessed is added to the costs to be amortized. Full cost accounting does not require the assessment of properties included in the amortization computation for impairment; rather, the cost pool in the aggregate is compared to the cost center "ceiling." The cost ceiling is further discussed under "Accounting for Production" in this chapter.

## EXPLORATION

85. The purpose of geological and geophysical exploration is to obtain information about subsurface geological conditions in an area that can be used in assessing the probability that oil or gas exists in commercial quantities. This involves first locating underground structures or stratigraphic variations that are conducive to the trapping of oil and gas, then carrying out detailed tests to see if drilling is justified.

### Origin and Accumulation of Oil and Gas

86. Oil and gas is generally believed to have originated from organic matter in sedimentary rocks. Layer upon layer of sediment and animal and plant deposits are buried until the accumulation is thick, possibly thousands of feet. Bacteria take oxygen from the trapped organic residues and gradually break down the matter into substances rich in carbon and hydrogen. The weight of the overburden creates high pressure and temperature, compacts and squeezes the sediment into hard shales, turns the organic material into oil and gas, and expels the oil and gas from the shale into reservoir beds.

87. Oil and gas are usually not found where they were formed. Source rocks, in which the organic material was originally trapped, are fine-grained and relatively impervious. They rarely hold oil and gas in significant quantities. The oil and gas normally move from the source rock into more porous rocks, then migrate upward through the porous rocks until they reach a structural closure or an impermeable barrier caused by stratigraphic variations. These closures and barriers are called traps and are the cause for accumulation of oil and gas into a pool or field.

88. An oil or gas reservoir is often erroneously viewed as a large pool of liquid or gas beneath the earth, like a subterranean pond. In reality, a petroleum reservoir is porous rock capable of containing gas, oil, or water. The petroleum is accumulated in the small pore spaces in the rock. For an oil and gas pool to be formed, the following features must be present:

- There must be a source bed of organic material, subjected to the proper temperature and pressure.

- There must be a reservoir rock—a rock filled with pores so the oil or gas can collect (porosity).

- The rock's pores must be interconnected so the oil or gas can move or migrate (permeability).

- There must be a trap that will cause the oil or gas to collect in a pool and prevent it from moving further upward.

## Prospecting for Oil and Gas

89. At one time, prospecting for oil and gas merely involved visible sightings of surface accumulations. The primary exploration technique used in many areas was surface geological mapping to define the structural features expressed in the rock outcrops that indicated an oil and gas trap would be present in the subsurface. However, these obvious drilling sites were rapidly developed and subsurface geological and geophysical studies were needed to locate petroleum reservoirs. Several scientific methods were developed including the seismic method, the magnetic method, and the gravity method. Surface geological studies, however, are still used to locate areas structurally favorable for oil and gas accumulations in new exploration areas.

90. Geological exploration activities include studying the structural configuration of exposed formations on the surface in order to secure information about the structure of parallel subsurface beds, examining the surface for oil or gas seepages or paraffin residue that indicates past seepage of hydrocarbons, and examining subsurface strata through the use of samples taken by core drilling and measurements of certain physical properties of the rocks such as resistivity and radioactivity. In addition, geologists and other scientists make many different tests of cuttings brought to the surface in the process of drilling wells.

91. Some large companies maintain exploration departments or establish exploration subsidiaries that own or lease geological and geophysical equipment and employ exploration crews and scientists. Most companies, both large and small, contract with exploration and oil industry service companies to carry out their exploration.

92. If an outside contractor is used, the contract normally contains detailed provisions about the area to be covered, the nature of work to be performed, the time period in which the exploration is to be carried out, the nature of reports to be made, rules for insuring security of data, and other provisions.

93. When the operating company maintains its own exploration department, it is customary for costs of that department to be accumulated and allocated to exploration activities and projects. The allocation is based on standardized charges, such as cost per day for a crew, costs per shot-point for seismic work, hourly basis for engineers, and the like. Frequently, employment contracts with geologists or geophysicists call for the employee to receive ownership interests in leases acquired as the result of exploration.

94. For control purposes, exploration is undertaken on a project basis. A "project area" is usually the maximum size that can be efficiently explored under a coordinated exploration program. A preliminary reconnaissance of the project area using magnetometers, gravitometers, aerial photography, and surface geology seeks to define "areas of interest" for oil and gas accumulations that justify more intensive exploration through seismic shooting or core drilling. The detailed exploration is conducted to determine more specific prospective

areas for evaluation with drilling and may be conducted either before or after acquiring the lease.

95. Once the seismic data has been analyzed and the leases acquired, the company determines the exact spot for drilling. Wells drilled in an unproved area are referred to as exploratory, or "wildcat," wells.

## Other Considerations

96. Some exploration can be conducted without direct access to privately owned land surface; for example, photography and gravimetric and magnetic measurements can be conducted from planes or satellites, and studies of surface strata can be made from creek beds or river beds and from public roads and railroads cut through hills. However, to gain access to private land the operator must secure permission from landowners. This transaction may involve a "rights to explore only" contract, which permits the operator to conduct exploration on the property but does not provide for subsequently leasing acreage. Permission may also be granted through a "rights to explore with option to acquire acreage" contract. This agreement calls for the operator to make a payment at the time the contract is signed, and it gives the operator not only the right to explore but also to lease all or part of the acreage by paying a specified bonus per acre within the option period—often six months.

97. Holders of mineral properties may make cash contributions to other operators who are drilling wells on nearby properties in exchange for which the operator conducting drilling provides the contributor with geological data, including samples from the well being drilled. Sometimes the transaction involves a "bottom hole contribution," calling for cash to be paid when the well has been drilled to a specific geological formation or to a specified depth. In other cases, the transaction involves a "dry hole contribution," which provides that the contribution is to be made only if the well being drilled does not find commercial reserves. If the well is a producer, no contribution is made.

## Accounting for Exploration Costs

98. Costs incurred in the geological and geophysical activities are commonly referred to as G&G costs. G&G costs include costs of topographical, geological, and geophysical studies; rights of access to properties to conduct those studies; and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Costs of carrying and retaining undeveloped properties, dry hole and bottom hole contributions, costs of drilling and equipping exploratory wells, and costs of drilling exploratory-type stratigraphic test wells are also included in exploration costs.

99. Successful Efforts. Under the successful efforts method, G&G costs, costs of carrying and retaining undeveloped properties, and dry hole and bottom hole contributions are charged to expense as incurred. The costs of drilling exploratory and exploratory-type stratigraphic test wells are capitalized, pending determination of whether the well has found proved reserves. If it is determined the well has not found proved reserves, the capitalized costs, net of any salvage value, are charged to expense. See "Accounting for Drilling and Development Costs" in this chapter.

100. <u>Full Cost</u>. Under the full cost method, all costs associated with the exploration of properties are capitalized within an appropriate cost center. These cost centers are established on a country-by-country basis by publicly held companies. The costs become part of the full cost pool.

## DRILLING AND DEVELOPMENT

101. Although most wells drilled by oil and gas operators are intended to find oil and gas and to extract minerals, some wells are drilled solely to obtain geological information (stratigraphic test wells) or to facilitate production (gas or water injection wells). Wells drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive are classified as development wells, while other wells drilled to find oil and gas are called exploratory wells.

102. Various drilling methods exist. Rotary drilling is by far the most prevalent method. Rotary drilling, as the name implies, involves the application of a rotating motion to a drill bit to bore a hole into the earth. A drilling fluid (mud) is continually circulated in the drilled hole to flush the cuttings from the hole as it is drilled.

103. Although well bores are normally planned to be drilled vertically, it is sometimes necessary or advantageous to drill at an angle, especially in offshore operations. Directional drilling makes it possible to drill a number of wells using the same rig from the same surface location. Directional drilling has other applications. Wells may be drilled from the shoreline and deflected to reach a reservoir offshore. It is also used, among other things, for exploratory drilling to locate the fault plane of a structure.

### <u>The Drilling Contract</u>

104. Operators may carry out drilling activities using their own rigs, or they may hire independent drilling contractors to drill wells. The terms of drilling contracts vary widely, but most involve footage-rate contracts, day-rate contracts, turnkey contracts, or a combination of the three.

105. Under footage-rate contracts, the drilling contractor is paid a fixed amount per foot drilled to a specified depth or number of feet below a geological formation. The drilling contractor provides the rig, the drilling crew, and certain materials and supplies. The operator may provide drilling mud and normally provides all well equipment. In a footage-rate contract, some of the risk of drilling is shifted from the operator to the drilling contractor. Generally, if the rig is idle due to no fault of the driller, a daily or hourly charge is specified. If the rig can only drill a few feet per day due to hard rock or other problems the drilling contractor bears the economic adversity.

106. Under day-rate contracts, the operator is charged a specified sum per day for the use of a drilling rig and drilling crew, which may vary depending on whether the rig is drilling or idle, the extent of equipment furnished, and other factors. The cost of a well bore hole is a function of the speed of the rig, the depth to be drilled, the geological formation encountered, and other

drilling factors. Typically, under day-rate contracts, the drilling contractor furnishes the rig and crew, but the operator provides supplies, mud, and services.

107. Under a turnkey contract, the contractor guarantees to deliver to the operator a hole drilled to a specified depth. The drilling contractor bears most of the risk of adversity associated with drilling costs. Turnkey contracts usually specify completing a well to a certain point such as to casing point, to completion, to tanks, or the like. The drilling contract specifies the point or points at which payment is to be made by the operator.

108. Frequently, an operator will assign an economic interest in the leasehold to another party in return for the latter's assumption of the cost of drilling a well. These drilling arrangements are discussed under "Conveyances" in this chapter.

## Completing the Well

109. Once the well has been drilled to total depth, the operator evaluates the evidence to determine whether the costs of completion can be justified. Completion of the well does not necessarily mean the well will be profitable. Generally, the well will be completed if the expected revenues exceed the incremental completion costs and the expected operating expenses. Therefore, even though total costs, including drilling costs, may not be recovered, completion may be economically justified.

110. In completing the well, casing is set and cemented into the hole, which seals off the producing formation. The most widely used method of completion is to perforate the casing with explosive charges that puncture through the casing and cement into the formation so the oil and gas can enter the well bore. Depending on the permeability of the formation, it may also be necessary to fracture or acidize the formation to obtain the required flow of oil and gas. These are specialized services, generally performed by independent well service companies.

111. Completion of the well also involves the installation of equipment. The specific equipment required will depend on the nature of the well, whether oil or gas or both are produced, the availability of pipelines, and other factors.

## Developing the Reservoir

112. Normally, a single well is not sufficient to complete the development of a reservoir. Additional wells usually increase the ultimate quantity of oil or gas to be extracted from the reservoir. They also affect the timing of the extraction and thus the present value of the income stream. While the presence of an oil and gas reservoir was established through the drilling of the discovery well, the property may or may not have sufficient potential reserves to warrant the further expenditures required for the complete development. Core samples, along with pressure tests, flow tests and rates, fluid analyses, and geological data are used in deciding whether to continue with development.

113. Assuming that a successful discovery well has been drilled, drilling and development will continue until the boundaries of the reservoir are delineated. A well drilled within the proved area of an oil and gas reservoir to the depth of a stratigraphic horizon known to be productive is classified as a development well. A well drilled to extend a known reservoir is classified as an exploratory well.

## The Regulatory Environment

114. Various state agencies issue regulations concerning well spacing limitations, rules regarding unitization of reservoirs, and allowable maximum production limits. Normally, the operator must obtain permits before exploration or drilling commences. Reports on well depths and results of drilling activities must be filed with the applicable agency. For example, if a well is determined to be dry or commercially unproductive, a plugging report is filed with the state agency. If a well is completed, various types of information, including production, must be filed on a regular basis with the appropriate state and federal agencies, including the Department of Energy (DOE), the Federal Energy Regulatory Commission (FERC), and the Minerals Management Service.

## Accounting for Drilling and Development Costs

115. Successful Efforts. Under the successful efforts method, all costs incurred while drilling an exploratory well are capitalized pending determination of whether the well has found proved reserves. If the well has not found proved reserves, the capitalized costs of drilling the well, net of any salvage value, are charged to expense. If an exploratory well or exploratory-type stratigraphic test well is in progress at the end of a period and the well is determined not to have found proved reserves before the financial statements for that period are issued, the costs incurred through the end of the period, net of any salvage value, are charged to expense for that period (FASB Interpretation No. 36).

116. All drilling and completion costs that directly lead to the extraction and production of oil and gas reserves and all development dry holes are capitalized. Capitalized costs are accumulated by cost centers, which provide a means whereby costs can be collected and amortized against the revenues generated therefrom. The cost center is the individual property for capitalization purposes or an aggregation of properties in the same field or reservoir for amortization purposes.

117. Because of the different treatment of dry holes, the distinction between exploratory and development drilling is extremely important and should be made by the company prior to drilling.

118. Full Cost. A company that employs the full cost method of accounting capitalizes all costs associated with the drilling and completion of a well, regardless of whether or not it results in the discovery of oil and gas reserves.

119. Interest Capitalization. Interest capitalization may be accounted for quite differently under the full cost and successful efforts methods. A signi-

ficant difference may occur between these two methods when a company following the full cost method does not elect to exclude costs of unevaluated properties from costs to be amortized. FASB Interpretation No. 33, Applying FASB Statement No. 34 to Oil and Gas Producing Operations Accounted for by the Full Cost Method, states that assets whose costs are being currently depreciated, depleted, or amortized are assets in use in the earnings activities of the enterprise and are not assets qualifying for capitalization of interest. Under the successful efforts method, capitalized costs of each property represent the company's assets. When a property is ready for production to commence, the capitalized costs of that property are considered "in the earnings activities of the enterprise," and are no longer qualifying assets. Costs of successful and unsuccessful exploratory efforts, including related leasehold costs, incurred on a property are qualifying assets until production commences on the property. Capitalized interest is attached to the qualifying costs on which the interest was computed and amortized in the same manner as those costs.

## OIL AND GAS RESERVES

120. The discovery of oil and gas reserves is the primary objective of exploration and development activities. In order to assure its long-term existence, an oil and gas producing company must continue to replace the reserves produced with newly discovered reserves.

121. Reserve determinations have a significant effect upon a company's results of operations and financial position. For a company following the successful efforts method of accounting, exploratory wells discovering proved oil and gas reserves will be capitalized instead of being expensed. Additionally, for both the successful efforts and full cost methods of accounting, amortization of capitalized costs is computed using the unit-of-production method, based on proved reserves or based on units of revenue. Further, under the full cost method, there is a limitation on capitalized costs in each cost center based on a calculated value of future net revenues from estimated production of proved oil and gas reserves.

122. As a result of the pervasive effect of reserve classification and volume estimates upon the financial statements of oil and gas producing companies, the auditor should understand the origin and accumulation of oil and gas deposits and the means by which the volumes of known deposits are estimated.

### Reserve Classifications

123. To consider the means by which reserves are determined or estimated, the auditor should be aware of the classifications into which reserves are divided. Those classifications of reserves are proved and potential (potential reserves can be further categorized as probable and possible). Only proved reserves are used for accounting purposes.

124. Proved Reserves. Proved oil and gas reserves (as defined by the SEC) are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and

operating conditions (prices and costs as of the date the estimate is made). Prices include consideration of fixed and determinable changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

125. Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (a) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, and (b) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

126. Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the proved classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provide support for the engineering analysis on which the project or program was based.

127. Proved developed reserves--Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as proved developed reserves only after testing by a pilot project or after the operation of an installed program has confirmed, through production response, that increased recovery will be achieved.

128. Proved undeveloped reserves--Proved undeveloped oil and gas reserves are proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those drilling units that offset productive units and that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

129. Subdivisions. Although variances will occur depending on the engineer responsible for the study, it is quite common to find reserve classifications further divided as follows:

- Producing reserves--Those reserves estimated to be recoverable from zones currently open and producing.
- Shut-in reserves--Those reserves estimated to be recovered from zones in which completions have been made in wells ready to produce and awaiting connection to delivery facilities.

- Behind-pipe reserves--Those reserves behind casing in producing wells.

130. Potential Reserves. Proved reserves have industry and regulatory definitions, but there are no such standards for potential reserves, which are often referred to as probable and possible. These reserve classifications are not subject to SEC disclosure. However, since potential reserves are commonly used terms in the industry, a set of definitions are offered as examples.

131. Probable reserves--Probable reserves are those that are supported by favorable engineering and geological data but are subject to some element of risk, which prevents classification as proved reserves.

132. Possible reserves--Possible reserves include speculative reserves where risk is relatively high. Usually, reserves to be included as possible are those that depend on some favorable development or event (such as creation of a unit to conduct fluid injection operations or remedial work to correct a mechanical defect) that is not predictable with good accuracy.

133. Definitional Problems. As indicated by the foregoing definitions, the classification of reserves is highly complex. Although the definition of proved reserves cited is from SEC regulations, it was derived directly from similar definitions developed by the Society of Petroleum Engineers of the American Institute of Mining, Metallurgical, and Petroleum Engineers. The definition of probable and possible reserves can vary significantly from one engineer to another.

Determination of Reserves

134. Reserve estimates are prepared by persons such as petroleum reservoir engineers and geologists with the specialized knowledge and experience required to estimate oil and gas reserves. The engineers may be either employees of the company or independent reservoir engineers. Reserve studies may also be prepared using various assumptions, each for different purposes.

135. Reserve estimates or studies are used for a variety of purposes, including—

- A basis for financing or investment decisions.
- A basis for management's projections of internally generated cash flow and as input for better operational decisions.
- A base for computing the depreciation, depletion, and amortization (DD&A) rates used in the systematic allocation of capitalized costs to the production function.
- Disclosure information about a producing company's resources, which is used in financial reporting to lenders, investors, analysts, and the SEC.
- A basis for determining cost ceiling limitations.

136. The initial evaluation of a well or wells is made to determine whether sufficient reserves have been discovered to justify developing the property.

This evaluation is usually prepared by employees of the company based on log and core data, drill stem tests, and other available information.

137. Oil and gas companies should revise reserve estimates whenever there is an indication of the need for revision, at least annually. The reserve estimates prepared for this purpose are usually as of the company's year-end. In many cases the estimate will be prepared by independent reservoir engineers.

138. Preparation of Estimates. The Society of Petroleum Engineers has adopted standards pertaining to the estimating and auditing of oil and gas reserve information by qualified engineers and geologists.[3] The auditor should have a general understanding of the methods of, and limitations on, estimating proved reserves.

139. The following information may be used to develop reserve quantity information:

- Area and thickness of the productive zone
- Porosity of the reservoir rock
- Permeability of the reservoir rock to fluids
- Oil, gas, and water saturation
- Physical characteristics of oil and gas
- Depth to the producing formation
- Reservoir pressure and temperature
- Production history of the reservoir
- Ownership of the oil and gas property

140. Estimates of the reserve quantities that are economically recoverable also include consideration of estimated selling prices and development and production costs. The methods used to estimate recoverable reserves vary with the amount and nature of the above information that is available. After a discovery, volumetric calculations are frequently used to estimate the volume of oil and gas in-place. The in-place volume is then converted into recoverable reserves by use of an estimated recovery factor. This factor is initially based on experience in the area and the type of reservoir drive. As production data become available, it is possible to estimate reserves from reservoir performance as well as volumetric calculations. The methods used for these combination-type procedures include material balance calculations, decline curves, and rate cumulative curves.

141. Precision of Estimates. According to the Society of Petroleum Engineers, the reliability of reserve information is considerably affected by several factors. Initially, it should be noted that reserve information is imprecise due to the inherent uncertainties in, and the limited nature of, the data base upon which the estimating of reserve information is predicated. Moreover, the methods and data used in estimating reserve information are often necessarily indirect or analogical in character rather than direct or deductive.

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[3] Society of Petroleum Engineers of AIME, Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information (Dallas: Society of Petroleum Engineers of AIME, 1980).

Furthermore, the persons estimating reserve information are required, in applying generally accepted petroleum engineering and evaluation principles, to make numerous judgments based upon their educational background, professional training, and professional experience. The extent and significance of the judgments to be made are, in themselves, sufficient to render reserve information inherently imprecise.

142. Reports. The reserve estimation process culminates in the preparation of a reserve report or reserve study. Generally, the study will contain a page for each reserve classification of each well. Summary pages are included for each reserve classification of each lease or field, and there usually is a summary page for the company total by each reserve classification. Each well page normally identifies the location, operator, and the revenue and working interest attributable to the appraised interest. Exhibits 1 and 2 are illustrations of a summary reserve report and a reserve report for an individual well.

# EXHIBIT 1



AS OF JAN 1, 1983
RUN DATE DEC 20, 1982

RESERVES AND ECONOMICS

INTERESTS AND DATE FIRST EFFECTIVE

| COST | LIQUID | GAS | DATE |
|---|---|---|---|

ALL STATES
TOTAL PROVED
ESCALATED CASE

| PRESENT WORTH | M$ |
|---|---|
| 10.00 | 282627.040 |
| 15.00 | 224586.260 |
| 20.00 | 186078.220 |
| 25.00 | 158849.420 |

>99% PAYOUT= 0.0YR

| | WELL COUNT GROSS | NET | API OR BTU | BASE PRICE | TRANS. CHARGE | PROD. TAXES | ADVAL TAXES | .... PRICES .... BEGIN | ENDING | LIFE WT | CF/BBL BL/MMCF | GROSS RESERVES CUMULATIVE | REMAINING | ULTIMATE | % GROSS REMAINING | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| OIL | 758. | 262.82 | | | 0.0% | 6.0% | 2.6% | 31.80 | 65.00 | 43.62 | | 16851.510 | 23448.576 | 40300.087 | 58.18% | OIL |
| GAS | 1670. | 759.40 | | | 0.0% | 4.8% | 2.1% | 3.45 | 7.00 | 5.45 | | 343240. | 571398. | 914638. | 62.47% | GAS |
| COND. | | | | | 0.0% | 7.1% | 1.7% | 31.80 | 65.00 | 42.54 | | 3650.367 | 4179.077 | 7829.444 | 53.38% | COND. |

| YEAR | GROSS OIL + COND PROD MBBLS | GROSS GAS PRODUCTION MMCF | GROSS DIR OPR EXPENSE M$ | NET OIL + COND PROD MBBLS | NET GAS PRODUCTION MMCF | EFF OIL & COND PRICE $/BBL | EFFECTIVE GAS PRICE $/MCF | OIL + COND SALES M$ | GAS SALES M$ | TOTAL SALES M$ |
|---|---|---|---|---|---|---|---|---|---|---|
| 1983 | 4003.540 | 76430.783 | 23800.977 | 552.593 | 10991.347 | 31.800 | 3.533 | 17572.492 | 38832.001 | 56404.493 |
| 1984 | 3566.537 | 70997.833 | 25216.824 | 632.049 | 12672.531 | 32.104 | 3.846 | 20291.293 | 48738.777 | 69030.070 |
| 1985 | 3054.457 | 66505.314 | 25523.264 | 594.525 | 13734.474 | 34.099 | 4.435 | 20272.825 | 60910.471 | 81183.295 |
| 1986 | 2251.622 | 51751.177 | 25436.049 | 402.836 | 10365.087 | 36.434 | 4.784 | 14676.964 | 49590.030 | 64266.994 |
| 1987 | 1810.943 | 37294.899 | 25498.047 | 312.734 | 7207.618 | 39.035 | 4.930 | 12207.424 | 35532.610 | 47740.034 |
| 1988 | 1583.134 | 29795.356 | 25338.511 | 274.312 | 5864.604 | 41.783 | 5.125 | 11461.484 | 30056.387 | 41517.872 |
| 1989 | 1395.777 | 28173.907 | 25123.567 | 243.841 | 5460.086 | 44.710 | 5.456 | 10902.114 | 29791.430 | 40693.544 |
| 1990 | 1204.285 | 24245.891 | 24535.264 | 215.078 | 4871.394 | 47.834 | 5.821 | 10287.929 | 28356.928 | 38644.857 |
| 1991 | 1118.619 | 18414.331 | 24405.248 | 192.862 | 4117.645 | 51.185 | 6.232 | 9871.605 | 25661.598 | 35533.203 |
| 1992 | 973.001 | 16053.165 | 23951.632 | 164.962 | 3711.445 | 54.769 | 6.651 | 9034.807 | 24686.225 | 33721.032 |
| 1993 | 886.519 | 15999.787 | 23741.474 | 154.691 | 3466.340 | 58.612 | 6.987 | 9066.726 | 24218.707 | 33285.433 |
| 1994 | 954.343 | 15439.624 | 22893.714 | 241.544 | 3279.903 | 61.909 | 7.004 | 14953.636 | 22973.198 | 37926.833 |
| 1995 | 671.776 | 15071.190 | 21633.960 | 103.037 | 3201.978 | 65.000 | 7.000 | 6697.400 | 22413.844 | 29111.244 |
| 1996 | 507.517 | 13602.781 | 19666.816 | 77.776 | 3007.886 | 65.000 | 7.000 | 5055.438 | 21055.205 | 26110.643 |
| 1997 | 400.752 | 11081.010 | 18113.717 | 64.237 | 2601.115 | 65.000 | 7.000 | 4175.420 | 18207.808 | 22383.227 |
| SUB TOTAL | 24382.824 | 490857.050 | 354879.060 | 4227.075 | 94553.452 | 41.761 | 5.087 | 176527.560 | 481025.220 | 657552.770 |
| REMAINDER | 3244.830 | 80540.726 | 179125.800 | 341.509 | 21825.019 | 65.000 | 7.000 | 22198.077 | 152775.110 | 174973.180 |
| TOT 82.3 YR | 27627.654 | 571397.780 | 534004.870 | 4568.584 | 116378.470 | 43.498 | 5.446 | 198725.630 | 633800.320 | 832525.950 |

| YEAR | DIRECT OPR EXPENSE M$ | NET ADVAL + PROD TAXES M$ | EFFECTIVE WPT TAX M$ | TOT OPR EXP + TAXES M$ | OPERATING REVENUE M$ | TOT INVEST TANG+INTANG M$ | BFIT CASHFLOW M$ | CUM BFIT CASHFLOW M$ | BFIT C.F. DISC @ 14% M$ | CUM C.F. DISC @ 14% M$ |
|---|---|---|---|---|---|---|---|---|---|---|
| 1983 | 6279.199 | 4171.867 | 1298.688 | 11749.754 | 44654.740 | 5489.391 | 39165.349 | 39165.349 | 36384.589 | 36384.589 |
| 1984 | 6949.257 | 5488.418 | 1005.735 | 13443.410 | 55586.660 | 21351.227 | 34235.434 | 73400.783 | 27046.037 | 63430.626 |
| 1985 | 7154.025 | 6405.866 | 787.014 | 14346.905 | 66836.391 | 12733.738 | 54102.653 | 127503.440 | 38379.972 | 101810.600 |
| 1986 | 7090.388 | 4817.631 | 513.628 | 12421.647 | 51845.347 | 3159.989 | 48685.358 | 176188.790 | 30644.296 | 132454.890 |
| 1987 | 7133.973 | 3350.759 | 407.693 | 10892.425 | 36847.610 | 3441.742 | 33405.867 | 209594.660 | 18416.653 | 150871.550 |
| 1988 | 7067.472 | 2829.424 | 306.774 | 10203.669 | 31314.203 | 244.900 | 31069.303 | 240663.960 | 15044.424 | 165915.970 |
| 1989 | 7036.412 | 2644.453 | 267.988 | 9948.853 | 30744.692 | 79.243 | 30665.448 | 271329.410 | 13027.894 | 178943.860 |
| 1990 | 7012.365 | 2462.451 | 238.695 | 9713.511 | 28931.347 | 6.838 | 28924.509 | 300253.920 | 10783.038 | 189726.900 |
| 1991 | 7003.070 | 2348.382 | 183.802 | 9535.254 | 25997.949 | 294.924 | 25703.024 | 325956.940 | 8401.873 | 198128.770 |
| 1992 | 6965.455 | 2212.453 | 84.076 | 9261.983 | 24459.048 | 42.057 | 24416.992 | 350373.940 | 7001.554 | 205130.330 |
| 1993 | 7017.348 | 2220.710 | 19.557 | 9257.614 | 24027.818 | 250.264 | 23777.555 | 374151.490 | 5979.205 | 211109.530 |
| 1994 | 6909.569 | 2591.002 | 0.000 | 9500.571 | 28426.262 | 569.972 | 27856.290 | 402007.780 | 6215.955 | 217325.490 |
| 1995 | 6598.334 | 1875.056 | 0.000 | 8473.391 | 20637.853 | 322.228 | 20315.625 | 422323.410 | 3933.308 | 221258.790 |
| 1996 | 6146.779 | 1632.284 | 0.000 | 7779.063 | 18331.580 | 183.129 | 18148.451 | 440471.860 | 3087.419 | 224346.210 |
| 1997 | 5756.402 | 1391.108 | 0.000 | 7147.510 | 15235.717 | 102.163 | 15133.555 | 455605.420 | 2255.674 | 226601.890 |
| SUB TOTAL | 102120.050 | 46441.863 | 5113.649 | 153675.560 | 503877.210 | 48271.804 | 455605.400 | 455605.420 | 226601.890 | 226601.890 |
| REMAINDER | 59972.055 | 9906.289 | 0.000 | 69878.344 | 105094.840 | 1352.641 | 103742.200 | 559347.620 | 7651.684 | 234253.570 |
| TOT 82.3 YR | 162092.100 | 56348.152 | 5113.649 | 223553.900 | 608972.050 | 49624.445 | 559347.600 | 559347.620 | 234253.570 | 234253.570 |

# EXHIBIT 2

AS OF JAN 1, 1983 — RESERVES AND ECONOMICS — PAGE: 1408
RUN DATE DEC 20, 1982

LEASE NAME: MILLSPAUGH, AUSTIN 2-12
FIELD NAME: OZONA
FORMATION : CANYON SAND

EVALUATION: SEQ.# 245 IN DB: MIDLRE.DB
OPERATOR :
CNTY,STATE: CROCKETT, TX

INTERESTS AND DATE FIRST EFFECTIVE

| COST | LIQUID | GAS | DATE |
|---|---|---|---|
| .3260000 | .2569791 | .2569791 | 1/1/83 |

IDENTITY: MTXOZO-MIL12-C7CAS-GA-4200019801-AND-PPD-O-SPC
NGPA 107
OFF. SPI & CCC. PART SO WEST GAS 79 & S. ANDERSON
RRC #88069

| PRESENT WORTH | M$ |
|---|---|
| 10.00 | 60.063 |
| 15.00 | 50.699 |
| 20.00 | 43.942 |
| 25.00 | 38.878 |
| 30.00 | 34.958 |

| | WELL COUNT GROSS | NET | API OR BTU | BASE PRICE | TRANS. CHARGE | PROD. TAXES | ADVAL TAXES | .... PRICES .... BEGIN | ENDING | LIFE WT | CF/BBL BL/MMCF | GROSS CUMULATIVE | RESERVES REMAINING | ULTIMATE | % GROSS REMAINING |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| GAS | 1. | 0.33 | | | 0.0% | 7.5% | 3.2% | 5.78 | 7.00 | 5.81 | | 42.306 | 127.362 | 169.668 | 75.07% GAS |

| YEAR | GROSS OIL + COND PROD MBBLS | GROSS GAS PRODUCTION MMCF | GROSS DIR OPR EXPENSE M$ | NET OIL + COND PROD MBBLS | NET GAS PRODUCTION MMCF | EFF OIL & COND PRICE $/BBL | EFFECTIVE GAS PRICE $/MCF | OIL + COND SALES M$ | GAS SALES M$ | TOTAL SALES M$ |
|---|---|---|---|---|---|---|---|---|---|---|
| 1983 | 0.000 | 10.800 | 7.470 | 0.000 | 2.775 | 0.000 | 5.963 | 0.000 | 16.550 | 16.550 |
| 1984 | 0.000 | 10.800 | 7.993 | 0.000 | 2.775 | 0.000 | 6.381 | 0.000 | 17.709 | 17.709 |
| 1985 | 0.000 | 13.045 | 8.553 | 0.000 | 3.352 | 0.000 | 4.123 | 0.000 | 13.822 | 13.822 |
| 1986 | 0.000 | 11.240 | 9.151 | 0.000 | 2.888 | 0.000 | 4.412 | 0.000 | 12.743 | 12.743 |
| 1987 | 0.000 | 9.684 | 9.792 | 0.000 | 2.489 | 0.000 | 4.721 | 0.000 | 11.748 | 11.748 |
| 1988 | 0.000 | 8.367 | 10.477 | 0.000 | 2.150 | 0.000 | 5.052 | 0.000 | 10.862 | 10.862 |
| 1989 | 0.000 | 7.637 | 11.211 | 0.000 | 1.962 | 0.000 | 5.407 | 0.000 | 10.611 | 10.611 |
| 1990 | 0.000 | 7.102 | 11.995 | 0.000 | 1.825 | 0.000 | 5.786 | 0.000 | 10.559 | 10.559 |
| 1991 | 0.000 | 6.605 | 12.835 | 0.000 | 1.697 | 0.000 | 6.191 | 0.000 | 10.507 | 10.507 |
| 1992 | 0.000 | 6.142 | 13.733 | 0.000 | 1.578 | 0.000 | 6.624 | 0.000 | 10.456 | 10.456 |
| 1993 | 0.000 | 5.713 | 14.695 | 0.000 | 1.468 | 0.000 | 6.976 | 0.000 | 10.241 | 10.241 |
| 1994 | 0.000 | 5.313 | 15.723 | 0.000 | 1.365 | 0.000 | 7.000 | 0.000 | 9.557 | 9.557 |
| 1995 | 0.000 | 4.941 | 16.307 | 0.000 | 1.270 | 0.000 | 7.000 | 0.000 | 8.888 | 8.888 |
| 1996 | 0.000 | 4.595 | 16.307 | 0.000 | 1.181 | 0.000 | 7.000 | 0.000 | 8.266 | 8.266 |
| 1997 | 0.000 | 4.273 | 16.307 | 0.000 | 1.098 | 0.000 | 7.000 | 0.000 | 7.687 | 7.687 |
| SUB TOTAL | 0.000 | 116.255 | 182.550 | 0.000 | 29.875 | 0.000 | 5.697 | 0.000 | 170.205 | 170.205 |
| REMAINDER | 0.000 | 11.107 | 48.921 | 0.000 | 2.854 | 0.000 | 7.000 | 0.000 | 19.980 | 19.980 |
| TOT 18.0 YR | 0.000 | 127.362 | 231.471 | 0.000 | 32.729 | 0.000 | 5.811 | 0.000 | 190.185 | 190.185 |

| YEAR | DIRECT OPR EXPENSE M$ | NET ADVAL + PROD TAXES M$ | EFFECTIVE WPT TAX M$ | TOT OPR EXP + TAXES M$ | OPERATING REVENUE M$ | TOT INVEST TANG+INTANG M$ | BFIT CASHFLOW M$ | CUM BFIT CASHFLOW M$ | BFIT C.F. DISC @ 14% M$ | CUM C.F. DISC @ 14% M$ |
|---|---|---|---|---|---|---|---|---|---|---|
| 1983 | 2.435 | 1.771 | 0.000 | 4.206 | 12.344 | 0.000 | 12.344 | 12.344 | 11.498 | 11.498 |
| 1984 | 2.606 | 1.895 | 0.000 | 4.501 | 13.208 | 0.000 | 13.208 | 25.552 | 10.792 | 22.290 |
| 1985 | 2.788 | 1.479 | 0.000 | 4.267 | 9.555 | 0.000 | 9.555 | 35.107 | 6.863 | 29.152 |
| 1986 | 2.983 | 1.364 | 0.000 | 4.347 | 8.396 | 0.000 | 8.396 | 43.503 | 5.290 | 34.443 |
| 1987 | 3.192 | 1.257 | 0.000 | 4.449 | 7.299 | 0.000 | 7.299 | 50.802 | 4.035 | 38.478 |
| 1988 | 3.416 | 1.162 | 0.000 | 4.578 | 6.284 | 0.000 | 6.284 | 57.086 | 3.047 | 41.525 |
| 1989 | 3.655 | 1.135 | 0.000 | 4.790 | 5.821 | 0.000 | 5.821 | 62.907 | 2.473 | 43.998 |
| 1990 | 3.910 | 1.130 | 0.000 | 5.040 | 5.519 | 0.000 | 5.519 | 68.426 | 2.057 | 46.055 |
| 1991 | 4.184 | 1:124 | 0.000 | 5.308 | 5.199 | 0.000 | 5.199 | 73.625 | 1.700 | 47.755 |
| 1992 | 4.477 | 1.119 | 0.000 | 5.596 | 4.860 | 0.000 | 4.860 | 78.485 | 1.394 | 49.149 |
| 1993 | 4.790 | 1.096 | 0.000 | 5.886 | 4.355 | 0.000 | 4.355 | 82.840 | 1.097 | 50.247 |
| 1994 | 5.126 | 1.023 | 0.000 | 6.148 | 3.408 | 0.000 | 3.408 | 86.248 | 0.754 | 51.001 |
| 1995 | 5.316 | 0.951 | 0.000 | 6.267 | 2.621 | 0.000 | 2.621 | 88.869 | 0.508 | 51.509 |
| 1996 | 5.316 | 0.884 | 0.000 | 6.201 | 2.065 | 0.000 | 2.065 | 90.934 | 0.351 | 51.860 |
| 1997 | 5.316 | 0.823 | 0.000 | 6.139 | 1.548 | 0.000 | 1.548 | 92.482 | 0.231 | 52.092 |
| SUB TOTAL | 59.511 | 18.212 | 0.000 | 77.723 | 92.482 | 0.000 | 92.482 | 92.482 | 52.092 | 52.092 |
| REMAINDER | 15.948 | 2.138 | 0.000 | 18.086 | 1.894 | 0.000 | 1.894 | 94.376 | 0.233 | 52.324 |
| TOT 18.0 YR | 75.460 | 20.350 | 0.000 | 95.809 | 94.376 | 0.000 | 94.376 | 94.376 | 52.324 | 52.324 |

143. The reserve study may present both net unrecovered reserve volume amounts and associated cash flow from production by year. Dollar values are generally attributed only to the subject producer's interest in projected annual production. Amounts presented for each remaining year of a property's economic life are—

- Production of gas and oil, unit prices, and gross revenues. Production prices are based on current prices, which include consideration of changes in existing prices provided by law, regulatory agencies, or contractual arrangements.

- Production expenses, including production taxes, operating expenses, windfall profit tax, and equipment and development costs. Production expenses generally do not include provisions for depletion, depreciation, or amortization. Further, reserve studies assume consumption of equipment during a property's producing life and do not ordinarily consider residual values of equipment or reclamation costs.

- Future net income (revenues less production expenses) or cash flow.

- Discounted (present) value of cash flow, generally computed at various rates.

## PRODUCTION

144. After the well is completed, the production phase begins. In the case of gas wells, the pressure in the reservoir is sufficient that when the well is opened, the gas expands into the well bore and flows to the surface. Oil wells, however, may be flowing wells, or they may require mechanical equipment that provides artificial lift to raise the oil to the surface.

145. However the product is lifted from the well, fluids produced are directed to a central gathering point, often a tank battery. Some fields may be equipped with lease automatic custody transfer (LACT) units that automatically measure the oil's temperature, gravity, and volume; drain off basic sediment and water (BS&W); and run the oil from the tank into the pipeline. The well area normally has all the equipment necessary to field-separate oil, gas, and water, plus adequate storage for the oil from the time it is produced until it is sold. Oil generally contains a certain amount of gas in solution, and usually some provision must be made to separate the gas from the oil before placing the oil in the storage tanks. The well fluids enter the oil and gas separator near the center, and the gas is removed from the top while the liquid (oil or water) is removed from the bottom.

146. At this point, the liquid is likely to contain a certain amount of water, which must be removed before the oil can be sold. For this purpose, it may be necessary to heat the liquid by passing it through a continuous type of heater. Generally, this is done in a heater-treater, which heats the oil and water mixture, separating the water from the oil in a single operation.

147. The tanks in the tank battery used to store the oil vary in number and size depending on the production of the lease and the frequency of the oil runs.

Each tank has a strapping table that converts the feet and inches measurement of oil in the tank to barrels of oil. There is a drain at the bottom of the tank for draining the BS&W.

148. When the tank is full, or at another predetermined time, the oil is "run," or delivered to a pipeline, tank car, or tank truck. The pipeline outlet valve on the tank is sealed closed with a metal seal while the tank is being filled from the well and is locked open when the tank is being emptied. This assures the pipeline company and the producer that only oil in a particular tank is entering the pipeline company's lines.

149. The oil delivered is measured by gauging the height of oil in the tank before and after delivery. The oil is also tested at this time to determine its gravity or density, its temperature, and its BS&W content. Crude oil prices are posted at a standard base temperature of sixty degrees Fahrenheit, and the value of the crude oil varies with its density. Therefore, these measurements, which are made when measuring the tank's contents, are recorded on the run ticket and are used in converting to net barrels delivered. It is the responsibility of the lease operator to watch the gauging and testing of the oil done by the gauger and to be sure that the measurements are correct.

150. When gas is produced, it may be run directly into the gas pipeline after being measured by an "orifice meter." If the gas contains liquid condensates, it may be run through a processing facility to remove the liquids, which are similar to crude oil, before the gas is turned into the pipeline.

151. When an outsider purchases oil or gas, settlement is usually made monthly. The purchaser customarily withholds and remits to the state the production or severance taxes on all production. Production taxes or severance taxes may be based on the quantity of production, on the value of production, or on a combination of quantity and value. The "first purchaser" is normally required to withhold and remit to the federal government the windfall profit taxes on oil production. However, in cases where the operator is an integrated producer and in certain other cases, the operator may withhold and remit the windfall profit tax on oil.

## Work-Overs

152. Occasionally, it is necessary to "work over" a well. Work-overs are remedial operations sometimes required to maintain maximum oil producing rates. If a well begins to produce an excessive amount of salt water, a work-over rig—very similar to a drilling rig but somewhat smaller—is moved onto the well, and remedial operations are conducted.

153. Where there is more than one producing interval in the well bore and a lower zone has been depleted, a plug-back to a higher zone is in order. The plug-back can be accomplished with a cement plug in the casing or with a bridge plug—a mechanical device that can be set in the casing to effectively seal off the casing below the point at which it is set.

## Improved Recovery Methods

154. More than half of the oil originally in place in a reservoir may remain in the reservoir after the cessation of primary operations. To plan operations for maximum economic recovery, usually all wells are tested at regular intervals. Oil wells are tested for the oil producing rate, the gas/oil ratio, the gravity, the salt-water production, and the BS&W. Gas wells are tested to determine their gas producing rates (open-flow potential), the gas/liquid ratios, and the BTU (energy) content. When production rates from primary recovery methods are no longer satisfactory, secondary and enhanced oil recovery, or tertiary, techniques may be used to attain maximum production of the reserves.

## Abandonment of Wells and Facilities

155. When oil and gas reserves are depleted or when production drops to the point that it is no longer economically feasible to produce, equipment is removed and operations are abandoned. Federal and state regulations and contractual obligations require that wells be plugged, all facilities and equipment removed, and the terrain restored to specified conditions.

## Accounting for Production

156. Revenues, production costs and expenses, and income taxes are treated in the same manner under full cost and successful efforts accounting, except for DD&A and impairment costs.

157. Revenue. Most companies recognize revenue from oil produced at the point of sale—that is, when the oil is run from the tanks. Gas is not stored on the lease; thus, revenue is recognized at the point of production and sale, as they are the same. However, some companies record revenue on a cash basis throughout the year, which will require an accrual adjustment at the end of the period under generally accepted accounting principles.

158. The company may record the revenue based on the remittance advice received from the purchaser. Generally, proceeds from production are received one to three months after the actual production has occurred. Thus, it may be necessary to estimate revenue, based on prior months' production and current lease operations (for example, whether the well has been shut in for a work-over or maintenance), in order to close the books on a timely basis.

159. Inventory. Oil in the lease tanks at the end of the accounting period is usually ignored for financial reporting purposes and inventory is not recorded because the amount of such oil normally is immaterial in relation to the financial statements.

160. When inventory of oil in lease tanks is recorded, valuation methods vary in practice from an allocation of production costs and DD&A to valuations based on market price.

161. Operating Expenses. Lease operating expenses such as pumpers' wages, fuel or electricity for operating pumping equipment, subsurface maintenance, surface

maintenance (such as lease roads and cutting of grass), insurance, ad valorem taxes, producing-well overhead, salt water disposal, fracturing, acidizing, and work-overs to maintain production are charged to expense. One exception to this occurs when a completion is made to a new zone, in which case that portion of the charges allocable to the completion may be accounted for as development costs and capitalized.

162. DD&A—Successful Efforts. DD&A of capitalized costs is recorded as the reservoir is produced and depleted. Under successful efforts accounting, DD&A is based on the unit-of-production method (a) for acquisition costs of proved properties on the basis of total estimated units of proved (both developed and undeveloped) reserves and (b) for all other costs on the basis of total estimated units of proved developed reserves. DD&A is computed using current-period production divided by beginning reserves (that is, reserves at the end of the period plus current-period production) either on a property-by-property basis or on some reasonable aggregation of properties with a common geological structure or stratigraphic condition such as a reservoir or field.

163. If "significant" development costs (such as an off-shore production platform) are incurred in connection with a planned group of development wells before all of the planned wells have been drilled, it is appropriate to exclude a portion of those development costs in determining the DD&A rate until the additional development wells have been drilled. Similarly, the proved developed reserves that will be produced only after "significant" additional development costs are incurred (as in improved recovery) are excluded in computing the DD&A rate. Future development costs are not considered when computing the DD&A rate under successful efforts accounting, although estimated dismantlement, restoration, and abandonment costs net of salvage value should be considered.

164. When a property contains both oil and gas reserves, the units of oil and gas used to compute amortization are converted to a common unit of measure on the basis of their relative energy content unless (a) the relative proportion of gas to oil is expected to continue throughout the life of the property, in which case DD&A may be computed on the basis of one of the two minerals only or (b) if either oil or gas clearly dominates both the reserves and current production, the DD&A rate may be computed on the basis of the dominant mineral only.

165. The issue of whether to provide for impairment of proved properties based on the amount expected to be recoverable is unsettled under generally accepted accounting principles. Similarly, when impairment is recognized, there is considerable variation in practice in valuing the amount recoverable and in determining the property unit to which the valuation test is applied.

166. DD&A—Full Cost. Full cost companies compute their DD&A of the full cost pool on a cost center basis using the depletion rate calculated on the unit-of-production method. The DD&A rate is computed on the basis of physical units, unless economic circumstances (related to the effects of regulated prices) indicate that use of the units-of-revenue method is a more appropriate basis of computing DD&A. If physical units are used in the computation, the oil and gas must be converted to a common unit of measure on the basis of their approximate relative energy content (generally, a ratio of six thousand cubic feet (MCFs) of gas to one barrel of oil is used), and the current-period production is divided by reserves at the beginning of the period (that is, reserves at the end of the

period plus current-period production). If the units-of-revenue method is used, the DD&A rate is computed on the basis of current gross revenues divided by the sum of (a) future gross revenues based on current prices (unless fixed and determinable changes in existing prices are provided by contract) from proved reserves and (b) current-period gross revenues. This DD&A rate is multiplied by the sum of (a) unrecovered costs in the pool, (b) estimated future expenditures based on current costs to be incurred in developing proved reserves (specified in the reserve report), and (c) estimated dismantlement and abandonment costs net of salvage value. Under certain circumstances prior to 1983, the cost of unusually significant investments in unproved properties and major development projects could be excluded from capitalized costs to be amortized. In September 1983, the SEC adopted Release No. FR-14, which provided that the cost of all investments in unproved properties and major development projects expected to entail significant costs could be excluded from capitalized costs to be amortized, subject to the following conditions:

- The properties are to be assessed at least annually for impairment.
- Dry hole costs are included in the amortization base immediately.
- G&G costs that cannot be directly associated with specific unevaluated properties are to be included in the amortization base as incurred.

167. Full Cost Ceiling. A full cost company also determines if the value of proved reserves and other mineral assets in the cost center are adequate to recover the unamortized costs in the full cost pool. This test, referred to as the full cost ceiling test, is to be computed for each full cost center. Specifically, under SEC requirements, the net unamortized costs less related deferred income taxes should not exceed (a) the present value, discounted at 10 percent, of future net revenues from estimated production of proved oil and gas reserves (as defined in Regulation S-X Rule 4-10(K)(6) plus (b) the cost of unproved properties and major development projects not being amortized plus (c) the lower of cost or estimated fair value of unproved properties included in costs being amortized less (d) the income tax effects related to the differences between the amount computed above and the tax basis of the properties involved. Any excess is charged to expense and separately disclosed during the year in which the excess occurs. Even if the cost ceiling subsequently increases, the write-off is not reinstated. However, the SEC, in Staff Accounting Bulletin No. 47, provided that events occurring subsequent to year-end but before the date of the auditor's report could be considered in determining a write-down. Specifically, if additional reserves become proved on properties owned at year-end or price increases become known that were not fixed and determinable as of year-end, the resulting increases in present value can be considered in computing the cost ceiling.

168. It should be recognized that some companies not subject to SEC requirements follow other methods of computing the cost ceiling.

169. Abandonments. Under successful efforts, normally no gain or loss is recognized if only an individual well or a single item of equipment is abandoned if the well is part of a group of proved properties constituting an amortization base and the remaining properties continue to produce. The asset abandoned or retired is presumed to be fully amortized, and its cost is charged against the

accumulated DD&A. Only when the last well or property ceases to produce and the entire property is abandoned is gain or loss recognized. However, if a catastrophic event or other major abnormality results in partial abandonment or retirement of a proved property or wells or related facilities, a loss is recognized at the time of abandonment or retirement.

170. Under full cost accounting, abandonment or retirement of proved properties, wells, and related facilities does not result in any gain or loss being recognized.

## CONVEYANCES

171. The oil and gas industry is capital-intensive and usually associated with considerable risks. These characteristics along with the wasting, nonregenerative nature of its most significant asset require companies to continually expand their exploration efforts and capital commitments. Oil and gas companies desiring to spread the risks and to generate the funds necessary to explore and develop properties will often convey an economic interest in a property to another party in return for financing or other considerations. A conveyance is the assignment or transfer of mineral rights, usually a portion of the working interest, to another entity. A conveyance may involve a transfer of all or part of the rights and responsibilities of developing and operating a property.

### Forms of Conveyance

172. Several types of economic interests are commonly associated with oil and gas properties. The "mineral interest" is the ownership of the right to explore for and produce the minerals underlying the surface of a property. An owner of the mineral interest would not necessarily own the surface rights. Most leasing transactions involve the lease of operating rights of the mineral interest to an oil company with the lessor retaining a royalty interest.

173. The working interest normally operates the property, paying most of the costs of exploration, development, and production. The working interest is also normally entitled to all the revenues generated by the property net of any royalties or overriding royalties. The working interest can also assign a portion of its interest, thereby creating a joint working interest. This allows the original working interest to spread its risk and share costs incurred.

174. Often, the working interest owner will carve out and convey to another entity a nonoperating interest. This interest may be an "overriding royalty interest," which is similar to a royalty interest except that it is created out of a working interest rather than the original mineral interest or a net operating interest.

175. Another interest created out of the working interest is the "production payment." Production payments are generally used to finance development of a property. The owner of a production payment is entitled to a specified share of the production of a property until a designated amount of money or product is generated from the property. After the terms of the production payment are satisfied, the interest reverts to the working interest from which it was created.

176. In addition to the sale of royalty or working interests and production payments, common forms of conveyances include free-well agreements, carried interests, farm-outs, and unitizations.

177. Under a free-well agreement, the working interest owner assigns a share of the working interest or some type of nonoperating interest to another party in return for the other party's drilling one or more wells on the property. If oil or gas is found, the parties immediately begin sharing revenues and expenses in the proportions called for in the contract, and neither party recovers any part of costs before sharing begins.

178. In cases where the working interest owner transfers all or part of the operating rights to an assignee in return for the latter's assumption of all or part of the development, the transaction is referred to as a farm-out. The assignor usually retains an overriding royalty but may retain any type of interest.

179. Carried-interest arrangements can be categorized into two types:

1. Carried interest for production property life. In this arrangement, one party (the carried party) assigns an individual portion of a lease to another party (the carrying party) to develop and operate until all costs—perhaps plus an additional percentage of such costs—have been recovered out of production from the property. At pay-out, the carried party begins to receive its share of the proceeds in excess of its share of the costs.

2. Carried interest for period of initial development. In this arrangement, the carried party begins to share in the revenues and expenses as soon as the carrying party recovers all costs incurred in connection with the drilling of the first well.

180. Another form of joint interest is a unitization. In unitization transactions owners of all interests in a geological structure agree to give up their shares in the individual properties, receiving in exchange a fractional share in the unitized properties. The interest received by each is usually in proportion to the estimated reserves contributed to the unit by that party. Since properties may not be at the same stage of development, it may be necessary for some parties to contribute cash and others to receive cash to "equalize" the values given and received for equipment and drilling costs.

<u>Accounting for Conveyances</u>

181. Mineral property conveyances and related transactions may be classified according to their nature as sales, borrowings, exchanges of nonmonetary assets, poolings of interests in joint undertakings, or some combination thereof. Accounting for conveyances is specified in some detail in FASB Statement No. 19 and Regulation S-X.

182. It is important that the auditor obtain a complete understanding of the economic substance of each conveyance. Because the form of conveyances will vary widely, and will often not fit exactly within the accounting literature

cited in the previous paragraph, a thorough understanding is necessary to reach a proper conclusion. In addition, the form of the conveyance may have significant tax consequences of which the auditor should be aware.

# CHAPTER 3

# TAX CONSIDERATIONS

183. Taxes represent one of the major costs affecting oil and gas producing companies. A general understanding of the principal types of taxes and their impact on the industry is essential to planning and conducting an examination of an oil and gas company's financial statements.

184. The discussion in this chapter is intended to be only an overview. Tax laws are subject to continuous change as a result of legislation, regulatory action, and judicial interpretation.

## INCOME TAXES

185. In general, income taxes affect oil and gas operations in the same manner as they do other companies. However, the income tax provisions related to oil and gas are among the most complicated, and, as a result, virtually every oil and gas company is faced with a variety of transactions that either must or may be treated differently for tax purposes than for financial reporting purposes.

186. Tax considerations affect the economics of many transactions in the industry to such an extent that they may become one of the determining factors in making decisions. Because of this economic effect and the impact on financial reporting, the auditor should have an understanding of some of the principal income tax considerations.

### Intangible Drilling and Development Costs

187. Intangible drilling and development costs (IDC) represent costs that are incurred incident to and necessary for the drilling of wells and the preparation of wells for the production of oil and gas and costs that are for items that in themselves have no salvage value. For example, items such as a drilling contractor's footage or daily rate charges, mud and chemicals, perforating, electric logging, and cementing qualify for treatment as IDC. Items such as casing and tubing do not qualify; however, the related cost of installation does. Costs applicable to line pipe, storage tanks, and comparable costs, including installation costs, are not considered IDC (not related to the drilling and preparation of wells for production), but are treated as part of the cost of tangible property.

188. A taxpayer may elect to deduct IDC by claiming a deduction for such costs on the tax return for the first taxable year during which the taxpayer incurred or paid such costs. A failure to deduct such costs is deemed an election to capitalize and deplete IDC. Such election is binding on the taxpayer for subsequent years.

189. Only 85 percent of IDC expenditures of an integrated oil company may be deducted in the year paid or incurred. The remaining 15 percent may be deducted

ratably over thirty-six months. An individual owning a working interest (other than through a limited interest) in a property may elect to capitalize IDC and amortize it over a five-year period. If an individual is allocated IDC deductions through a limited partnership, such costs are subject to an election to be amortized ratably over a ten-year period. These elections are in addition to that applicable to deducting IDC. An individual may be inclined to make such elections for various reasons, for example, to avoid minimum tax payments.

## Depletion

190. Producers of oil and gas are entitled to a deduction for depletion to recover capitalized leasehold costs. The costs to be recovered through depletion represent those that must be capitalized in connection with acquisition of the taxpayer's interest in the property and that are not recoverable through depreciation (including capitalized IDC). Such costs may represent bonuses paid to a lessor, amounts paid for a royalty interest, G&G costs required to be capitalized, and other types of expenditures related to acquisition of the interest.

191. Depletion deductions include cost and percentage depletion. All taxpayers are entitled to cost depletion deductions. Deductions for percentage depletion are covered by specific exceptions to a general rule that such deductions are normally not allowable with respect to oil and gas production. Percentage depletion is available to certain taxpayers under an exemption applicable to specified domestic gas wells and another exemption applicable to independent producers and royalty owners. The allowable deduction for depletion is the higher of percentage or cost depletion, determined on an individual-property basis. Percentage depletion in excess of the tax-cost basis in a property is a permanent difference in determining the provision for income taxes.

192. The auditor should be aware of the importance attached, for tax purposes, to associating the producer with the holding of an economic interest. The holder of the economic interest in the property is the party who may be entitled to the deduction for depletion. The producer of crude oil, for windfall profit tax (WPT) purposes, is the party ultimately liable for the tax, and the holder of the economic interest is the producer. An economic interest in the property can be held by a taxpayer as the result of a direct interest held in the minerals through a fee title resulting from a lease, through an assignment from the original lessee (or previous assignees of the original lessee), or through another contractual arrangement (such as certain net profits interest arrangements). Under IRS rules, the holder of the interest must have the right to share in proceeds from the sale of the reserves as opposed to a right to receive compensation for services rendered.

193. An independent producer is defined as one who does not directly, or through a related party, engage in certain specified retailing or refining activities involving oil and gas or products derived therefrom. Independent producer status can result in substantial benefits with respect to both income taxes and WPT. From an income tax standpoint having such a status would control eligibility for deducting percentage depletion. For WPT purposes, a producer must have such status in order to be eligible for certain lower rates and an exemption attributable to specific types of crude oil.

Conveyances

194. As discussed in chapter 2, conveyances in the oil and gas industry take a wide variety of forms. In many of these transactions, the income tax treatment varies significantly from the accounting treatment. Because of the effect on the financial statements and the economic impact, conveyances should be carefully reviewed and the terms and provisions analyzed to determine the appropriate tax treatment.

Common Timing Differences

195. In addition to timing differences related to IDC deductions and depletion provisions, other common timing differences that may be encountered, depending on the method of accounting used, for financial statement purposes, include—

- o Costs capitalized for financial statement purposes but expensed for income tax purposes:
  - Exploratory and development dry hole costs.
  - Delay rental costs.
  - Internal costs associated with exploration and development.
  - Certain types of G&G costs.
- o Abandonments of properties resulting in deductions for income tax purposes but not expensed for financial statement purposes.
- o Provisions for impairment of properties expensed for financial statement purposes, but not for income tax purposes.
- o Differences between depletion and depreciation amounts for financial statement purposes and income tax purposes.
- o Gains recognized on the sale of properties for income tax purposes but credited to the carrying value of oil and gas properties for financial statement purposes.
- o Income from management fees or other types of drilling arrangement income recognized for income tax purposes but credited to the carrying value of oil and gas properties for financial statement purposes.

196. Exhibit 3 summarizes the most common timing differences.

EXHIBIT 3

COMMON TIMING DIFFERENCES

| Timing Difference | Successful Efforts | Full Cost | Income Tax |
|---|---|---|---|
| Prospecting Costs (Preacquisition exploration costs) | | | |
| G&G costs | Expense | Capitalize | (1) |
| Exploration Costs (Post-acquisition) | | | |
| Carrying costs of undeveloped properties: | | | |
| Delay rentals | Expense | Capitalize | Optional |
| Ad valorem taxes | Expense | Capitalize | Optional |
| Legal costs of title defense | Expense | Capitalize | Capitalize |
| Direct costs of maintaining land and lease records | Expense | Capitalize | Expense |
| Costs to prepare well location for drilling exploratory wells and intangible drilling costs: | | | |
| Proved reserves are found | Capitalize | Capitalize | Expense (2 |
| No proved reserves are found | Expense | Capitalize | Expense |
| Dry hole contribution | Expense | Capitalize | (3) |
| Bottom hole contribution | Expense | Capitalize | Capitalize |
| IDC (Development Wells) | Capitalize | Capitalize | Optional ( (usually expense) |
| Disposition of Capitalized Costs | | | |
| Depletion | Expense | Expense | Expense (5 |
| Abandonments: | | | |
| A property that is a portion of an amortization base becomes worthless | No loss recognized | No loss recognized | Loss recognized |
| Book provision for abandonments | Expense | N/A | Nondeducti |
| Amortization base becomes worthless | Loss recognized | Loss recognized | Loss recognized |
| Conveyances and Related Transactions | (7) | (7) | (7) |
| Sale of Part of an Interest Owned | | | |
| Substantial uncertainty exists concerning recovery of costs applicable to retained interest or seller has substantial obligation for future performance | No gain recognized, loss recognized | No gain or loss recognized | Gain or lo recognized |

COMMON TIMING DIFFERENCES

(Continued)

(1) G&G costs are capitalized if such costs would be associated with the acquisition of a property; otherwise they are deducted.

(2) Tax treatment of costs of drilling exploratory-type stratigraphic test wells is unsettled.

(3) Income tax treatment is unsettled. IRS position is that dry hole and bottom hole contributions should be capitalized (Rev. Rul. 80-153). Many taxpayers continue to contend that all dry hole contributions should be expensed, as should bottom hole contributions if dry.

(4) Intangible costs of drilling disposal wells are capitalized and depreciated for tax purposes. IDC related to certain carried interests should be separately identified since it may have to be capitalized for tax.

(5) The difference between tax depletion and book depletion may be a timing difference. "Tax preference" depletion (depletion in excess of basis) is a permanent difference.

(6) Loss is recognized only if total property is abandoned, no deduction for partial abandonments.

(7) Conveyances and related transactions could cause timing differences. Such transactions should be investigated on an individual basis to determine any differences between book and tax recording. Consider special tax treatment of carried interests (Rev. Rul. 77-176), farm-outs, tax partnerships, and the like.

(8) Conveyances of an interest where conveyer retains an overriding royalty, net profits interest or other interest should be separately identified since tax treatment is different than when an outright sale occurs.

WINDFALL PROFIT TAXES

197. The WPT is an excise tax assessed on the removal of domestic crude oil. It is not an income tax, although WPT liabilities are limited by a statutory provision based on defined net income from a property. For WPT purposes, "domestic crude oil" is divided into two principal categories, exempt and taxable. Exempt is defined by law and includes oil applicable to certain governmental and charitable entities, certain "front-end incentive oil," exempt stripper well oil, exempt royalty oil, and exempt Indian oil.

198. An independent producer, as discussed under "Depletion" in this chapter, is entitled to certain benefits with respect to production attributable to a working interest owned by such a producer. Lower rates and even a complete exemption are applicable to certain specified production. Certain crude oil attributable to a qualified royalty owner's interest may also be exempt from the WPT. The exemption applies to specified limits of production attributable to a nonoperating interest (not a working interest) owned by an individual, estate, or family farm corporation.

199. Windfall profit subject to the WPT is limited to 90 percent of the net income from the property. Net income is defined by the statute and is computed on the basis of the income tax definition of a property. Basically, net income is comparable to that determined for percentage depletion purposes, except that WPT costs and IDC are not deducted. An election is provided to capitalize certain injectant expenses, and a deduction is provided for "imputed cost depletion" (depletion deductions computed as though IDC and injectant expenses had been capitalized from inception, if applicable).

200. Administrative provisions of applicable statutes and IRS regulations impose certain reporting, certification, and data-furnishing requirements on the producer, purchaser, and operator. Failure to comply with such requirements can result in assessments for additional taxes, interest, and penalties.

201. The tax is normally withheld by the purchaser from the production applicable to a producer who is not an integrated oil company. Such withholding requirements may be assumed by other parties (including the producer) as the result of being able to make certain elections. The purchaser of crude oil, any party assuming the purchaser's withholding obligations, and any producer not subject to withholding of the WPT on its own production are required to file excise tax returns at specific times and deposit the tax in accordance with specified schedules.

202. Differences between the amount of the WPT withheld and the correct amount of the applicable tax may be handled by withholding adjustments during subsequent periods. If the differences have not been adjusted through withholding, the annual report furnished to the producer may indicate that the WPT was either overwithheld or underwithheld for the calendar year covered by the report. Accordingly, the producer may be required to either file an excise tax return and pay the tax due or file a claim for refund or credit covering the overwithheld WPT.

203. When the tax is overwithheld or excessive deposits made due to application of the net income limitation, claims for credit or refund may be filed. In the

case of any overpayment, the producer may claim a credit against current income tax liabilities by so indicating on the applicable income tax return, or he may file a claim for refund. Such returns or claims for refund are seldom prepared before the financial statements are issued. Therefore, an estimate of the WPT refund is normally made for financial statement purposes.

## AD VALOREM AND SEVERANCE TAXES

204. Ad valorem and severance taxes are assessed by state and local taxing authorities. Again, a detailed coverage of ad valorem and severance taxes is not considered to be within the scope of the guide. However, the following points are worth mentioning:

- Severance and ad valorem taxes are deductible for income tax purposes. Both must be allocated to the appropriate property when calculating "net income from the property" applicable to determining limitations for percentage depletion and WPT.
- Severance and ad valorem taxes are normally applicable at the revenue-interest level (as opposed to lease operating expenses applicable at the working-interest level).

205. Tax reporting requirements for severance and ad valorem taxes will vary depending on the applicable state or local statutes and regulations.

# CHAPTER 4

# INTERNAL CONTROL CONSIDERATIONS

206. The system of internal accounting control of a company engaged in oil and gas exploration and production activities may be simple or very complex. The nature of a particular company's system is influenced by the size of the company, the degree of geographic dispersion of its operations, its types of operations (for example, operator vs. nonoperator), governmental requirements, and management's information needs.

207. In general, internal accounting control for oil and gas producing activities is not different from that of other types of enterprises. SAS No. 1, section 320, provides guidance on the auditor's considerations in the study and evaluation of the company's system of internal accounting control. Most of the business functions of companies engaged in oil and gas exploration and production activities are similar to the corresponding functions found in other types of businesses. However, certain business functions of the exploration, development, and production activities are unique. Internal control considerations for some examples of these types of functions are discussed below; they are not always present or required for the auditor to perform the examination in accordance with generally accepted auditing standards.

## LEASE RECORDS

208. Accurate records of nonproducing and producing properties and the related financial obligations should be maintained. For example, failure to pay delay rental payments on time can result in the loss of a valuable asset. Also, ownership interests in oil and gas properties are often complex and may change on the occurrence of certain events. Generally, a company maintains master files of lease records that contain all essential ownership and financial obligation information. The internal controls for this function would normally cover authorization of updates of those master files, integrity of processing master file transactions, periodic substantiation of master file contents, and prevention of unauthorized access to or alteration of data.

## DIVISION-OF-INTEREST FILE MAINTENANCE

209. The revenue from oil and gas producing properties is generally divided among multiple royalty and working interest owners. The operator with responsibility for remitting the revenues to the various interest owners should have reasonable assurance that all remittances are accurately computed. Typically, information about the ownership of revenue interests will be maintained in division-of-interest master files. The internal controls should provide for accurate and timely updating of the information, as well as prevention of unauthorized access to or alteration of the data. Division orders should be reviewed or adequately tested by individuals who do not have control over the properties.

JOINT INTEREST BILLING

210. Many oil and gas exploration activities are conducted jointly by two or more investors. Generally, accounting responsibility for a project is contractually defined. The operations and allocations are governed by an operating agreement. A company conducting joint operations should have internal controls that give reasonable assurance that all costs attributable to joint operations are identified and recorded, that the proper investor accounts are charged, that amounts due from investors are collected, and that accurate and timely statements of account are provided to the co-owners. The importance and difficulty of administering joint interest operations is increased because such operations often involve special cost allocations, carried interest arrangements, and other complexities. Most joint interest agreements also provide the nonoperating party with the right to perform (or have performed) joint interest audits of the operator within certain time limits.

REVENUE AND REVENUE PAYABLES

211. A company may receive oil and gas revenues from properties for which it is the operator as well as from properties operated by others. The internal controls should provide reasonable assurance that the company receives all production revenues to which it is entitled. Such controls may involve periodic calibration and inspection of meters, manually gauging or witnessing the gauging of production tanks, and period-to-period comparison of production volumes. In addition, settlement reports should be reconciled to the production data regularly. Prices should be monitored to ensure that maximum allowable prices are received. For revenues received on behalf of other co-owners, the amounts to be remitted must be accurately computed based on division-of-interest file information. Provisions for royalties payable should be consistent with the basic lease or royalty agreements and any questionable areas related to the computation of royalties due may be referred to legal counsel for interpretation. Detailed trial balances of royalties in suspense should be reviewed on a regular basis, and investigations of significant balances and fluctuations should be made by an employee with no conflicting duties.

PROPERTY ACCOUNTING

212. The tax and financial reporting requirements of accounting for oil and gas properties are unique and complex. Generally, cost, expense, and revenue information is accumulated at the individual lease or well level regardless of the accounting method used. Subsidiary property records should be routinely reconciled to the general ledger. The internal controls should provide for the proper capitalization or expensing of exploration costs, computation of depletion for both tax and financial reporting purposes, and identification of amounts recorded for oil and gas properties that are not realizable. In addition, property records should have sufficient detail of ownership, status (abandonments, lease brokerage inventory, operations), assigned equipment, and so on. This requires coordinating the land department, the legal department, and the accounting department. Procedures should be established for review of joint interest billings (JIBs) and comparison against the appropriate authorizations for expenditures (AFEs), for review of AFEs for credits due when a project

is completed, and for consideration of joint interest audits on a timely basis. There should be a proper segregation of duties between those responsible for preparing an economic assessment of the value of proved or unproved properties and those who have the authority to acquire or dispose of the properties. Procedures should also provide for a routine review of potential impairment.

213. Procedures should be established to determine that property transactions are properly authorized, including selection of properties, amount of expenditures, location and types of resources to explore and develop, and the levels and timing of production and inventory maintained. The timing and terms of sales or other dispositions of property should also be properly authorized.

PHYSICAL SECURITY

214. The substantial investment in physical assets and the ready marketability of equipment and inventory necessitate appropriate controls over access. Also, many sites are in rather remote areas and may be unattended for long periods of time. Physical barriers and restricted access along with detection and prevention devices should be considered. In addition, specific responsibility for physical custody of assets and signature access (requisition authority) is applicable.

AUTHORIZATION FOR EXPENDITURE

215. An AFE, which is a procedure for documenting authorization of large expenditures, usually contains a description of the project, a listing of budgeted expenditures, and appropriate approvals. An AFE should be required for acquisition of each major fixed asset. They are normally required for all costs incurred in acquiring leases, drilling and equipping oil and gas properties, purchasing drilling equipment and service units, constructing buildings, and other major projects. The company should have established procedures to follow up on variances between actual expenditures and the amounts in the AFEs.

COST ACCRUALS

216. Operators should have controls to provide reasonable assurance that accruals are made for exploration and development costs incurred. Normally, such accruals are based on field reports of estimated completion percentages of AFEs in progress. Procedures should also be established to assure that estimated production expenses are accrued if significant. Nonoperating interest owners should similarly accrue payables to operators for their share of expenditures incurred. This may require procedures for confirmation with the operator on properties on which activities are in progress.

GOVERNMENT REQUIREMENTS

217. Oil and gas producing activities are subject to numerous federal and state regulations. Noncompliance with these regulations can result in legal actions including fines, assessments, and other potential liabilities. In addition, there are certain tax regulations such as the WPT, ad valorem taxes, and statu-

tory depletion allowances, both at the federal and state levels. Procedures should be established and competent personnel employed to monitor and comply with the various governmental requirements.

## RELATED PARTIES

218. Unique financing arrangements, royalty relationships, management fees, and tax partnerships, among other arrangements, tend to be conducive to related party transactions. Systems and procedures should be established to accumulate the necessary information for disclosure requirements in accordance with FASB Statement No. 57, *Related Party Disclosures*.

# CHAPTER 5

# AUDITING

219. This chapter is intended to assist the auditor in applying generally accepted auditing standards in examinations of the financial statements of companies with oil and gas producing activities. It is presumed that the auditor has knowledge of generally accepted auditing standards. Accordingly, this guide does not expand on all the auditing considerations necessary to perform an examination in accordance with generally accepted auditing standards. Financial accounting for oil and gas producing activities is unique in many areas and presents problems for the auditor in determining whether the financial statements are presented in accordance with generally accepted accounting principles. This chapter is intended to identify these unique accounting areas and provide general guidance on the most effective way of auditing them. Auditors should use their professional judgment in applying this guidance to develop specific audit procedures that will meet their particular needs.

## AUDIT FOCUS

220. In audits of oil and gas producing activities the primary focus is on the company's properties. Evaluating the accumulation and realization of costs associated with the properties is central to the audit process and to determining whether the financial statements are presented in accordance with generally accepted accounting principles.

## AUDIT PLANNING

221. Audit planning involves developing an overall strategy for the expected conduct and scope of the examination. SAS No. 22, _Planning and Supervision_, should be consulted for general guidance on audit planning. There are certain other factors that the auditor should consider in planning an examination of the financial statements of a company with oil and gas producing activities.

### _Nature of Operations_

222. It is important for the auditor to consider the company's method of operation in planning the audit. Responsibilities associated with property operation will vary widely. Among matters to be considered would be the extent of operating responsibilities, the use of partnerships or joint ventures, and related party transactions.

223. _Operator or Nonoperator_. A distinction can be drawn between audit procedures designed to be used in the examination of the financial statements of a producer acting as an operator of properties and audit procedures used in the examination of the financial statements of a company acting solely as a nonoperator to joint operating agreements. Some of the factors to consider are—

- The terms of the operating agreement concerning the duties and responsibilities of the operator and the rights and obligations of the nonoperators.

- Whether the operator's policies and procedures provide reasonable assurance of compliance with the provisions of the operating agreement, provide proper and prompt billing of costs and expenses to nonoperators, and provide distribution of revenues to royalty-interest owners and nonoperator working interest holders.

- Whether the nonoperator's policies and procedures provide reasonable assurance of proper accounting for costs and expenses and that billings received from the operator are properly supported and in compliance with the terms of the operating agreement.

- Whether or not joint interest audits are periodically performed.

224. Nonoperators generally require significantly less accounting and operations personnel than would an operator. The operator will have the responsibility for paying all costs of development and operation of the property, properly billing such costs to the nonoperators, and often collecting and distributing revenues. On the other hand, the nonoperator pays and collects only its share of the costs and revenues, and generally no more often than once a month.

225. SAS No. 44, Special-Purpose Reports on Internal Accounting Control at Service Organizations, provides guidance on the examination of financial statements of a company that obtains the following services from another organization:

- Executing transactions and maintaining the related accountability

- Recording transactions and processing related data

- Various combinations of these services

226. In most instances an oil and gas company will maintain its own system of internal controls and accountability for nonoperated properties, independent of the operator's system. However, in some cases, a nonoperator may rely on the operator in a manner similar to that described for service organizations in SAS No. 44. The auditor's report on procedures and controls at a service organization described in SAS No. 44 will seldom, if ever, be found in practice in the oil and gas industry. If, in this case, the nonoperator's auditor does not intend to rely on the internal accounting controls at the operator, he should obtain an understanding of the flow of transactions through the operator and apply substantive procedures at the operator or engage the operator's auditor to do so (see SAS No. 35, Special Reports—Applying Agreed-Upon Procedures to Specified Elements, Accounts, or Items of a Financial Statement).

227. Use of Partnerships. The use of partnerships for financing purposes usually adds significant complications to the accounting and auditing of an oil and gas company. Many companies create limited partnerships by selling limited partner interests in public or private offerings. Often, the limited partnership agreements require audits of the partnership, which may require using a

lower materiality factor for testing partnership transactions than for direct transactions of the company.

228. In addition, the terms of the partnership agreement dictate the allocation of costs and revenues to the limited and general partners and often require a determination of the status of individual properties, or groups of properties, within the partnership. Therefore, audit procedures should encompass the information necessary to make such determinations.

229. Related Party Transactions. The nature of oil and gas operations tends to result in a greater frequency and significance of related party transactions than would occur in many other industries. This is largely due to the readily divisible nature of property ownership, but also occurs from dealings with limited partnerships, joint ventures, and the like. Commonly encountered related party transactions include—

- Employee interest in properties, particularly through incentive plans that enable key employees to earn an interest in successful prospects.

- Participation in properties with directors. Particularly in smaller companies, a frequent source of prospects may be directors who are themselves independent operators in the industry.

- Transactions with limited partnerships, including handling property transactions and allocating costs. Limited partnerships often involve conflicts of interest, in which decisions may benefit or adversely affect either the company or the limited partners.

230. In planning the audit, consideration should be given to determining that information necessary for related party disclosures is available and that procedures for testing the related accounts are designed to comply with SAS No. 45.

231. Other Considerations. Other contracts and agreements related to property operations that may require consideration in the planning of specific audit procedures include the following:

- Long-term sales contracts
- Drilling contracts
- Take-or-pay contracts
- Production payments
- Farm-outs and carried interests
- Leases, particularly expiration provisions
- Production-balancing contracts
- Division orders

## Geographical Considerations

232. The procedures used by the auditor during an examination of an oil and gas producing company's financial statements may be greatly affected by the geographical areas in which the company operates. For example, offshore operations and operations in foreign countries may require the auditor to consider—

- Different types of property costs associated with offshore as opposed to onshore operations.
- Various environmental and other regulatory implications.
- Production-sharing contracts with foreign governments.
- Tax implications of foreign operations.
- Disclosure requirements of foreign operations.

Identifying Personnel With Specific Functions

233. Identifying specified personnel, and their geographic location, having the responsibility for specific functions related to accounting, internal control, and financial reporting is an integral part of planning the examination.

234. Field Operation Accounting Personnel. Field operations may be conducted in a manner whereby the accounting data for investments in, and operations of, oil and gas properties are processed in the company's home office. On the other hand, certain functions may be performed in district or field offices. The auditor identifies the personnel, and their location, responsible for specific items, such as—

- Preparing and approving AFEs and subsequently reconciling actual costs with estimates.
- Measuring and reporting units of production.
- Pricing production.
- Approving expenses and allocations to specific properties.
- Joint interest billing and revenue sharing.
- Handling warehouse receipts and issuing materials.
- Complying with regulations.

235. Geological, Geophysical, and Engineering Personnel. Financial statements and reports to management for companies with oil and gas producing activities require that certain data be made available that call for the input of personnel other than accounting department personnel. This information includes—

- Status of wells.
- Reserve data about units, production curves, future development and operating costs, and the like.
- Production data analyses of pricing, number of units, conversion factors, and so on.

- AFE data, for example, identification of capital vs. expense workovers.

- Value information and exploration plans for measuring impairment and cost ceiling.

236. Land Department Personnel. These personnel may assist in providing information regarding—

- Property identification.

- WPT data.

- Transfers from undeveloped properties to producing leaseholds or abandonments.

- Current status of contractual obligations applicable to leasehold rights such as delay rental payments, drilling obligations, and payout status.

When making the inquiries referred to above, the auditor should also plan to identify the procedures used by the company's personnel in accumulating, processing, and validating the data involved.

## Use of Specialists

237. The nature of the oil and gas industry often requires the use of independent consultants or contractors such as reservoir engineers and geologists. SAS No. 11, Using the Work of a Specialist, provides guidance to the auditor who uses the work of a specialist in performing an audit. In addition, SAS No. 33, Supplementary Oil and Gas Reserve Information, describes standards prepared by the Society of Petroleum Engineers for qualifications of a reserve estimator.

238. The auditor preferably should make an early assessment of the extent of use of specialists and the timing considerations thereof, including the need for involving independent consultants. The auditor may consider outlining these needs in the audit engagement letter.

239. For companies using the full cost method of accounting, the extent to which an independent outside specialist is used may depend on whether a cost ceiling limitation problem is considered likely to exist (see discussion under "Accounting for Production" in chapter 2). This is a judgmental area; however, auditors should consider the advisability of requesting the involvement of an independent outside specialist when it appears the costs are approaching or may exceed the cost ceiling limitation.

## Tax and Other Regulatory Matters

240. Various tax and other regulatory matters can have a significant impact on an independent oil and gas company's financial statements. The auditor should make inquiries about the status of federal and state income tax matters and severance and property tax reporting matters. The auditor should also review the determination of the producer's status as an independent producer due to the

substantial impact such a determination could have on income tax and WPT liabilities. (See discussion under "Depletion" in chapter 3.) In addition, certain inquiries concerning WPT should be made. These include—

- o Status of depository or withholding requirements and compliance with applicable reporting requirements.
- o Procedures used to test the accuracy of amounts withheld or deposited and to compute amounts refundable under the net income limitation.
- o The company's reporting responsibility due to its role as general or managing partner in existing partnerships.

Other regulatory matters include—

- o Pricing procedures used in, and personnel responsible for, compliance with applicable statutes and regulations.
- o Reporting to state regulatory authorities (which states are involved, what reports must be filed, what procedures are used to accumulate applicable data, and so on).
- o Reporting to the SEC (current status of filings, identification of data, responsible personnel, and the like).

## AUDIT CONSIDERATIONS

241. This section will identify and discuss certain audit considerations of some of the business functions and accounts unique to oil and gas producing companies. The procedures selected to achieve the particular audit objectives should be adapted to the specific circumstances of the company. The areas discussed include property, receivables, payables, expenses, revenues, and other considerations.

### Property

242. The tests of property accounts of companies with oil and gas producing activities require careful consideration by the auditor. Property generally represents the most significant item in the balance sheet and is often the most difficult to test. Reliance is often placed on estimates by the company's operations department and management assertions. Following are several areas that deserve special attention in the tests of oil and gas property accounts:

- o Property costs
- o Interest capitalization
- o Production equipment inventory
- o Conveyances
- o Abandonment costs
- o Dry hole costs
- o Wells in progress
- o Depletion, depreciation, and amortization
- o Capital cost limitations

243. Property Costs. Joint interest owners share in acquisition, exploration, development, and production costs in accordance with the cost-sharing provisions of the joint operating agreement. Carried and reversionary interest provisions (among many other similar arrangements) often cause the sharing of costs to be different than the permanent lease ownership. The auditor should be familiar with the cost-sharing provisions of each property in order to effectively audit property costs.

244. For cost-control purposes, an AFE is prepared for most exploratory and development drilling activities and major projects undertaken by joint interests. The AFE gives the operator approval to incur specified dollar amounts in accomplishing agreed-upon tasks. The auditor might compare actual costs incurred by the operator with AFE amounts for evidence of unauthorized or excessive expenditures. Indications of potential charges or credits from joint interest audits impending or in progress should be evaluated in accordance with FASB Statement No. 5, Accounting for Contingencies.

245. Depreciation of support equipment and facilities used in oil and gas producing activities is properly accounted for as exploration, development, or production costs, depending on the activity with which the support equipment or facilities are involved. The auditor should consider appropriate audit procedures to determine that depreciation of support equipment is properly allocated.

246. A standard procedure in auditing property accounts of any commercial enterprise is testing physical existence. Physical examination of many types of oil and gas property is sometimes impractical and often alternative procedures are performed. For instance, producing wells are frequently too widely dispersed and too numerous to be examined. Alternately, the auditor may examine production records maintained by the operations department to determine that production proceeds were being received on the property as of the end of the period. Likewise, leasehold rights are intangible, and ownership is evidenced only through a lease or assignment document. Absolute verification of the company's ownership in a lease would require a title search, which is a time-consuming and expensive process. For this reason, the auditor might test ownership by examining a lease agreement and lease file. Additionally, examination of a delay rental payment is further evidence of the company's retention of its interest in the lease. The auditor may also obtain signed representations that the subject lease was not sold, assigned, or otherwise disposed of during the period.

247. Interest Capitalization. In determining whether capitalized interest is properly accounted for, the auditor should check that the qualifying assets have not previously entered the earnings activities of the company and determine that interest capitalized is properly computed.

248. Production Equipment Inventory. Operators of oil and gas properties often hold or have production equipment inventory stored by independent storage yards for use in future drilling activities and operations. Frequently, equipment will be transferred to a property in which the operator has an interest. The operator charges the joint account for the equipment and bills nonoperating interest owners for their share of the equipment pursuant to the joint operating agreement. Likewise, equipment is often transferred back to a storage yard upon the abandonment of a well. The operator issues credit to the nonoperating

interest owners for their share of the condition value attached to the inventory as dictated by the accounting procedures supplement to the joint operating agreement. The auditor should consider procedures to identify equipment movements and test the propriety of the accounting treatment for such movements. Depending to some degree on the extent of internal controls in effect, the auditor might confirm the existence of inventory with independent yards or might consider it necessary to observe the taking of a physical inventory. As with other industries, the auditor should determine that inventory is not carried at amounts in excess of market value, and he should review for obsolescence. Excessive quantities may indicate a need for write-down or classification as noncurrent.

249. Conveyances. Oil and gas property conveyances can take a variety of forms, each of which may be unique. The auditor should evaluate the accounting treatment of conveyance transactions in accordance with the conveyance provisions of FASB Statement No. 19 and Regulation S-X. The auditor should also be aware of the considerable differences between the financial accounting and income tax treatments of conveyances in the review of the company's income tax accrual.

250. Abandonment Costs. Accounting for abandoned wells and leases is discussed under "Production" in chapter 2. For abandoned unproved leases not expiring under their own terms, the auditor may obtain representations from the company that it does not intend to promote, develop, or sell the lease, or to pay future delay rentals when they come due, and that it has all necessary approvals. For leases that expire under their own terms or due to failure to perform drilling obligations, the auditor should consider appropriate procedures to determine that the company no longer has an interest in the lease and that the company has properly approved and recorded the abandonment. When wells are abandoned the operator is required to file a plugging report with the appropriate state governmental agency. The auditor might examine the plugging report to substantiate the abandonment of the well and, where applicable, determine that proper credit was granted to joint owners for salvageable lease and well equipment.

251. Dry Hole Costs. Under the successful efforts method of accounting, dry hole costs of an exploratory well are expensed when a determination is made that the well has no proved reserves. The auditor can usually substantiate the success or failure of a drilling effort by examining drilling reports from the drilling company (or operator for nonoperating interest owners). If drilling reports are unavailable, the auditor can examine a plugging report filed by the operator as support of the unsuccessful outcome of a well.

252. Wells in Progress. The accounting treatment for costs associated with exploratory wells in progress at the end of a reporting period is unique only under the successful efforts method. Costs of an exploratory well that has no apparent future benefits should be expensed. The auditor uses all information available in evaluating the status of an exploratory well as of the report date. Occasionally, a well is drilled and it cannot be immediately determined whether the property has proved reserves. This often happens because the property appears marginally economical or a major capital expenditure is required before production can begin. Usually if a decision about the economic viability of a well cannot be made within one year, the well would be considered

impaired and the costs charged to expense. A well requiring a major capital expenditure is carried as an asset only if the well has a sufficient quantity of reserves to justify its completion. If the drilling of additional wells is necessary to determine if reserves are sufficient, the company decides whether it is warranted to incur the additional capital expenditures. In addition, the drilling of the wells must have commenced or be firmly planned in the future in order to be carried as an asset. The auditor evaluates all available information to determine if capitalization of costs is proper under the above criteria.

253. Depletion, Depreciation, and Amortization. The methods used in computing DD&A under the full cost and successful efforts methods are discussed under "Production" in chapter 2. The key to auditing DD&A is to substantiate the DD&A rate and the DD&A cost base to which the rate is applied. In testing the DD&A rate, the auditor should inquire about the methods and bases used in the reserve study and their consistency with other available information. Current-year production quantities may be tested in conjunction with the testing of oil and gas production revenues. The cost base to which the DD&A rate is applied pertains to each cost center under the full cost method and on a property-by-property or an aggregation-of-properties basis under the successful efforts method. The auditor should test the cost base used in the computation and determine if all costs excluded from the cost base are properly excludable. The full cost method requires including estimated future development costs in the company's cost base. The auditor should review the company's estimated future development costs; determine if they are reasonable, given estimated future development activity; and compare them to the reserve report. The auditor should also determine whether these costs are based on current costs.

254. Unproved properties are periodically assessed to determine if they have been impaired. Accounting for impairment of unproved property costs is discussed under "Acquisition of Mineral Properties" in chapter 2. The auditor should review the company's procedures in providing for impairment and evaluate the adequacy of the provision. In evaluating the adequacy of the impairment provision, the auditor should use such information as the company's plans, dry holes drilled in areas near the company's leases, and lease expiration dates, as it is more likely that impairment exists on leases whose expiration dates are approaching. The auditor should be aware that top leases may be impaired by drilling activities of the original lessee, whether successful or not.

## Capital Cost Limitations

255. Full Cost. The full cost method prescribes a ceiling test for capitalized costs. The auditor should review the components of the cost ceiling computation and determine that they are computed in accordance with the prescribed guidelines. The rationale behind the ceiling test is that oil and gas property costs should be recoverable from the underlying assets. Therefore, any capitalized costs, net of accumulated DD&A and related deferred income taxes, in excess of the ceiling are written off to expense. In those situations where costs approach or exceed the ceiling, it may be advisable to consider consultation with independent outside specialists.

256. Successful Efforts. In contrast with the full cost method, the issue of whether to provide for impairment of proved properties based on the amount

expected to be recoverable is unsettled under the successful efforts method (see FASB Statement No. 19, paragraph 209). The recoverability of proved property costs is evaluated based on the underlying reserves; the recoverability of unproved property costs is evaluated based on the estimated fair market value of the unproved properties. The auditor should consider appropriate audit procedures to determine if the value of the properties is sufficient to recover the capitalized costs. If recovery of the capitalized costs is questionable, the auditor should consider the need for an independent outside specialist. If the auditor's procedures indicate the estimated fair market value of the reserves and unproved properties is less than the capitalized costs, the auditor should consider the effect on his opinion.

## Receivables

257. The general approach in auditing receivables from oil and gas producing activities is in many respects similar to that followed in auditing receivables of commercial enterprises. The confirmation of accounts receivable is a useful procedure for most accounts; however, special consideration should be given to the performance of additional or alternative audit procedures in the following areas:

- Joint interest billings (JIBs)
- Joint interest credits
- Oil and gas sales
- Production imbalances
- Cash calls
- Collectibility

258. Joint Interest Billings. Nonoperating interest owners can normally confirm the JIB balance as of the examination date; however, the validity of joint interest receivables is often dependent solely on the operator's accuracy in preparing the underlying JIBs. Accordingly, the auditor should consider procedures to test the validity and accuracy of the charges supporting the JIB statements as well as the percentages charged to nonoperating interest owners. At the examination date the property operator may have incurred obligations on behalf of the joint owners that have not been billed. These unbilled obligations also represent JIB receivables that, except for the omission of confirmation testing, should be considered for testing by the auditor.

259. Joint Interest Credits. Nonoperating parties normally have the right to audit the accounts and records of the operator relating to the joint account. These audits often result in credits being granted to nonoperating parties. The nonoperator's auditor should determine whether the nonoperator has recorded accounts receivable for credits granted and evaluate possible credits from audits in progress or impending in accordance with the gain contingency provisions of FASB Statement No. 5. These procedures also apply to the audit of accounts payable of an operating company where the operator is subject to issuance of potential joint interest credits.

260. Oil and Gas Sales. Oil and gas production sales are generally recorded by producers from run tickets or remittance advices received from purchasers of the production. Remittance advices are usually received from one to three months

after the purchaser takes control of the production. Oil and gas revenue transactions may be recorded on a cash basis; however, the producer should accrue estimated unreceived production revenues and related WPT and production taxes at the financial statement date. Such estimates consider production volumes, revenue interests, sales price histories, and appropriate deductions. The auditor should test the accrual through appropriate means, for example, agreeing production quantities used in the estimate to independent production records (or run tickets, if available), comparing revenue interest or royalty interest percentages with appropriate division orders, and substantiating the reasonableness of sales prices and tax withholdings used in the accrual.

261. Production Imbalances. Oil and gas production from a property is usually sold to purchasers for the benefit of all joint owners of that property. The purchasers then usually remit the sales proceeds to joint owners in accordance with the distribution provisions of the division order covering the property. Most standard joint operating agreements allow joint owners the option of taking their share of production in kind rather than having it sold to purchasers on their behalf. Where revenue interest owners take their share of production in kind, it is likely that the owners have taken more (overlift) or less (underlift) production than they are entitled to as of the examination date. The auditor should review the company's entitlement computation and consider confirmation procedures to substantiate any production imbalance receivables or payables recorded at the examination date.

262. Cash Calls. Under the provisions of most joint operating agreements the operator of a property can require nonoperating interest owners to advance their share of the estimated cash outlay for the succeeding month's drilling activities and producing property operations of the joint account. In these cases, the operator is entitled to these advances upon proper notification to the nonoperating interest owners. Where applicable, the auditor should consider confirming cash calls receivable with nonoperating interest owners and review the operator's computations supporting the cash call to determine if amounts requested approximate anticipated expenditures for operations in the following month.

263. Collectibility. Collectibility of joint interest accounts receivable in the oil and gas industry traditionally has not been a problem because of the remedies available to operators in the event of nonpayment or default. Operators have a preferred lien on the ownership interest of nonoperating parties. Under the provisions of the standard operating agreement, the operator can collect from oil and gas purchasers the proceeds accruing to the interest of the delinquent party up to the amount owed. Where it appears that an operator will have to collect amounts due in this manner, the auditor should determine that the delinquent party's share of future proceeds will cover the uncollected balance and the appropriate balance sheet classification. Disputes can arise over joint interest ownership percentages in oil and gas production and requested natural gas pricing classifications can be disallowed by the Federal Energy Regulatory Commission. The auditor should inquire of company management whether such disputes or potential disallowances exist and perform appropriate audit procedures to determine that the effect of any such disputes is properly reflected or disclosed in the financial statements.

Payables

264. Liabilities related to oil and gas producing activities are in many ways similar to those of a typical commercial enterprise. Accordingly, procedures in these areas are not necessarily unique; however, certain liabilities deserve special attention because of their peculiarity to the oil and gas industry. Many of these liabilities arise from the various everyday activities and transactions between operators and nonoperators of joint properties. The following are some of the more unusual areas:

- Joint interest payables
- Revenue distribution
- Borrowings from production purchasers
- Unapplied advances
- Production taxes payable

265. Joint Interest Payables. JIBs sent to nonoperating interest owners from operators generally provide very little detail about the timing of exploration, development, and production expenditures incurred by the operator. Therefore, these JIBs are not particularly useful when nonoperating parties accrue accounts payable as of the examination date. Nonoperating interest owners accrue these expenditures based on the best available information from the company's operations department (or from the operator if more accessible). Usually, such information can be adequately estimated from a schedule of AFEs, which details all open AFEs, AFE costs, the company's working interest in the related properties, and the completion percentage of each AFE. The auditor should consider appropriate audit procedures to substantiate the completeness of the schedule of open AFEs and review the AFE data contained in the schedule with operations personnel for reasonableness.

266. Revenue Distribution. Production revenues generated from a property are distributed by purchasers in accordance with the provisions of the division order executed by the joint owners of the property. Joint owners often collect production proceeds on behalf of other joint or royalty owners and make appropriate disbursements to them on a periodic basis. At the examination date, a proper cutoff is important. The party designated to collect such proceeds accrues accounts receivable (revenues net of tax withholdings) with an offset to a payable-to-royalty-owner's account. Depending on taxing jurisdiction regulations or contractual agreements, the responsibility for payment of severance or production taxes may lie with the purchaser, the operator, or the working interest owners individually. Occasionally, proceeds collected are in dispute and are recorded in a "royalty suspense" account. This type of liability is not relieved until the dispute is resolved. The auditor should consider appropriate audit procedures to identify those properties on which the company collects revenues on behalf of royalty and other joint owners. Special attention should be given to royalty suspense payables, as they may accumulate over extended periods of time before the underlying disputes are resolved.

267. Under the terms of many lease agreements, lessors are entitled to shut-in well payments, mandatory or minimum royalty payments, and payments of a similar nature. As of the balance sheet date, lessees accrue such mandatory payments to lessors. The auditor should inquire of operations personnel and perform audit procedures to identify potential obligations and determine their proper treatment in the financial statements.

268. Borrowings From Production Purchasers. Enterprises seeking sources of oil and gas supplies sometimes advance cash to property owners to finance exploration or development. The auditor might confirm borrowings and satisfy himself that the terms of the borrowing arrangement have been complied with. The auditor should consider the substance of the transactions involving advances from purchasers because they sometimes take the form of mineral sales whose treatment is addressed under "Conveyances" in chapter 2.

269. Unapplied Advances. As discussed previously, property operators may call nonoperating parties for cash advances to cover the estimated expenditures to be incurred in the following month's operations. As the operator incurs expenditures on behalf of nonoperating interest owners, their share of the expenditures is applied against advances received. Unapplied advances as of the financial statement date are liabilities to nonoperating interest owners and might be confirmed by the auditor. Joint interest owners will usually be able to confirm only the advances made to the operator less reductions for their share of expenditures incurred as represented on JIBs received from the operator. The validity of JIBs depends on the operator's accuracy in preparing them. The nonoperator's auditor should consider testing the validity and accuracy of the underlying charges supporting the JIB statements.

270. Production Taxes Payable. Production taxes are payable to state or other governmental agencies by either the purchaser or producer as determined by state or other governmental agencies. Where the producer is liable for the taxes, the operator usually pays production taxes on behalf of all joint interest owners. The auditor should determine that the operator has properly recorded the liability for state taxes and test the propriety of recorded production taxes payable.

## Expenses

271. This section deals with expenditures and other charges that are classified as expenses under both the successful efforts and full cost methods and that are unique to the oil and gas industry. This section does not deal with expenses arising from the amortization or write-off of assets such as abandonment expenses, depletion and depreciation expense, amortization expense, and the like. These expenses are dealt with under "Property" in this chapter. Two types of expenses that should be given special consideration are (1) work-over expense and (2) district and warehousing expenses and administrative overhead.

272. Work-Over Expense. AFEs may be prepared for well work-overs where charges are expected to exceed a minimum amount. The auditor should determine the nature of well work-overs and test the propriety of the company's classification of the work-over charges as capital or expense items. In addition, actual charges should be compared to the AFE (where an AFE has been prepared) and a determination and evaluation made of any apparent excessive or unauthorized charges.

273. District and Warehousing Expenses and Administrative Overhead. The operator of a property is allowed to allocate to the joint account certain overhead charges. The accounting procedures supplement to the joint operating agreement specifies the types of charges that can be allocated. The nonoperator's auditor

should determine that the allocated charges are in accordance with the accounting procedures supplement and that the company was charged for its proper share of the expenses.

Revenues

274. Revenues from oil and gas producing activities are typically of two types: production revenues and property conveyances. The following are items that may be considered by the auditor in conducting an audit of these revenues:

- o Sharing in and accountability for oil and gas sales
- o Pricing regulations and contractual agreements
- o Property conveyances
- o Revenue accumulation
- o Take-or-pay contracts
- o Lease brokerage activities

275. Sharing In and Accountability For Oil and Gas Sales. Oil and gas sales may be recorded from purchase remittance advices received from oil and gas purchasers. The auditor should consider tests to determine if production quantities on which sales proceeds were received agree to independent production records maintained by the operations department to substantiate that the company is receiving its proper share of revenues generated from a property or properties. The sharing of oil and gas production revenues by joint owners can be affected by a number of different arrangements. For instance, many joint interest drilling ventures call for joint interest owners to drill a free well or incur a higher percentage of the drilling costs (carried interest) than their permanent ownership interest in the property in return for contributions (for example, leasehold and exploration expenses) by other joint interest owners in the venture. Oftentimes these joint interest owners are entitled to all or a proportionately higher interest in generated production revenues until they recover a specified amount of costs. When these costs are recovered, their revenue interest reverts to their permanent interest in the property. Another common arrangement occurs when a joint interest owner declines participation (nonconsents) in drilling, deepening, plugging, plugging back, or reworking a well. The consenting parties must then incur proportionately higher costs to perform the specified task and, accordingly, are entitled to all of the nonconsenting parties' interest in generated revenues until they recover a predetermined percentage of their actual costs incurred. This percentage is commonly in excess of 100 percent of actual costs to compensate the consenting parties for their risk in the venture. Various other such arrangements exist that can alter the sharing of revenues. The auditor should consider examining division orders and other substantive evidence to test the propriety of the company's revenues.

276. Pricing Regulations and Contractual Agreements. Oil and gas producing activities are subject to complex pricing and tax regulations governing oil and gas sales. In testing oil and gas revenue, the auditor should consider appropriate procedures to determine if the company is receiving maximum allowable prices (in some cases the market will not bear the maximum allowable price) or prices in excess of existing price ceilings, which may require future refunds. In first year audits, compliance procedures should be considered to determine if potential refunds exist from excessive prices received from prior-year oil and gas sales.

277. Natural gas producers may contract with purchasers to sell certain quantities of their production at specified prices. The auditor should consider testing prices received for natural gas to determine if they agree with the terms of related contracts and comply with applicable regulations.

278. Property Conveyances. Accounting for oil and gas property conveyances is complex and should be reviewed by the auditor to determine if they are recorded in accordance with their underlying substance and applicable accounting pronouncements. From a revenue standpoint, the primary concern in testing conveyances is to determine that the company is immediately recognizing or deferring income, as appropriate. Although the accounting treatments are complex, audit procedures necessary to test conveyance transactions are not particularly unusual and will not be discussed further here. The auditor should be alert for future obligations that often accompany conveyance transactions and that may affect the accounting treatment and the possible need for footnote disclosure. It is important that the auditor obtain an understanding of the economics of the transaction to properly evaluate the accounting treatment.

279. Revenue Accumulation. Oil and gas producing companies should accumulate revenue and expense data on a property-by-property basis. Financial data on a detail-property basis are needed for several reasons, including computation of the WPT net income limitation, royalty payments, percentage depletion computations, income tax obligations, and internal decision-making concerning the economics of individual properties. Since the auditor is concerned with this same data for auditing purposes, tests to determine that detail property data are properly accumulated should be considered. The auditor may then be able to rely on this financial data in other related audit areas.

280. Take-or-Pay Contracts. Sometimes gas producers and purchasers will execute an agreement whereby a purchaser agrees to take or pay for a minimum quantity of gas per year. Usually, any amount paid in excess of the price of gas taken is recoverable from future purchases in excess of minimum quantities. If the purchaser is not allowed to make up deficiencies, it is appropriate for the producer to record revenues to the extent of the minimum contracted quantity, assuming payment has been received or is reasonably assured. If deficiencies can be made up, receipts in excess of actual sales should be deferred until production is actually taken or the right to make up deficiencies expires. The auditor should consider examining such contracts to determine the propriety of the accounting treatment and to identify possible contingencies. In addition, these contracts may impose an obligation on the producer to furnish a minimum amount of product. To the extent such product cannot be produced from the property, the producer may have a contingent liability to obtain the product from third parties. The auditor should evaluate such contingencies for possible losses or disclosure.

281. Lease Brokerage Activities.[4] Occasionally, a company may be engaged in the business of buying and selling undeveloped leases in addition to exploring for, developing, and producing oil and gas. In this instance, leases acquired

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[4]This paragraph is based on SEC Staff Accounting Bulletin No. 47. As the guide went into production the SEC was considering rule amendments to the practices described here (Release No. 33-6484).

and held for sale are properly classified as inventory. It is generally agreed that companies engaged in both lease brokerage activities and exploration and production activities should maintain strict separation of properties related to the two activities. Such separation should commence at the acquisition date and be maintained throughout the holding period of the property. The auditor might obtain from management representations of the company's business purpose and evaluate the proper accounting therefor.

Other Audit Considerations

282. Other considerations that the auditor should address in auditing oil and gas companies include nonoperators, joint ventures and partnerships, and reserve quantity and value disclosures.

283. Nonoperators. In conducting the audit of a company that owns nonoperating working interests or royalty interests, the underlying accounting support for costs and revenues will generally be statements from the operators of the properties. Depending on the materiality of nonoperated properties, the financial condition and reputation of the operator, and the nature of the relationship between the operator and the nonoperator, it may be necessary to inspect the operator's accounting records and perform other tests to obtain sufficient, competent, evidential matter with regard to certain audit objectives.

284. Each visit to an operator's office should be planned to ensure that all pertinent audit objectives are satisfied while at the operator's location. In certain instances this work can be coordinated with the nonoperator's internal or joint interest audit function; however, joint interest audits are normally performed so long after the fact that they are of only limited value to the independent auditor. Examples of some of the audit procedures that could be performed at the operator's office are—

- Examining third-party charges to support JIBs or revenue distributions to the nonoperator.

- Examining land department records to ensure timely payments of delay rentals and timely receipt of title opinions and curatives.

- Reviewing operating agreements to ensure that overhead and similar charges are in compliance with those documents.

- Reviewing division orders and comparing with operators' disbursements of revenues to the various interest owners to determine that revenues from production have been properly allocated and remitted to the royalty and working interest owners.

285. Joint Ventures and Partnerships. Although joint interest arrangements are the most common form taken by companies in sharing the risk of exploring for and developing oil and gas properties, joint ventures and partnerships are other common arrangements. An interpretation of APB Opinion No. 18 states that pro rata consolidation of the assets, liabilities, revenues, and expenses of unincorporated joint ventures is often used where it is established industry practice, as is the case in the oil and gas industry. The auditor should review and understand the structure of unincorporated joint ventures to determine if the company accounts for its investment in such joint ventures properly.

286. Reserve Quantity and Value Disclosures. Public companies with oil and gas producing activities are required by the SEC and the FASB to present certain supplementary reserve quantity and reserve value information outside of the basic financial statements. Although this supplementary information is not required to be audited, it is required to be disclosed by FASB Statement No. 69. The contents of the supplementary reserve quantity and reserve value disclosure information are defined in FASB Statement No. 69. The auditor is required by SAS No. 27, Supplementary Information Required by the Financial Accounting Standards Board, and SAS No. 33, Supplementary Oil and Gas Reserve Information, to perform certain procedures with respect to the reserve information.

287. The auditor's objectives in applying procedures to the supplementary disclosures are threefold:

1. To determine that the supplementary information prepared by the company is in conformity with prescribed guidelines and is presented in a manner consistent with prior-year presentations

2. To determine that reserve quantity estimates are prepared by persons with appropriate qualifications

3. To determine that the reserve information is consistent with the information in the underlying financial statements

288. To meet these objectives, the auditor should apply the procedures specified in SAS No. 27 and SAS No. 33. Performing those limited procedures, along with any additional procedures the auditor considers necessary, should give the auditor an adequate basis in determining whether the reserve quantity and reserve value information is presented in accordance with prescribed guidelines. However, an additional consideration may be appropriate. Independent reservoir engineers often use and rely on information, without corroboration, provided by the company in formulating their reserve quantity information. This information includes listings of the company's properties, the company's ownership interest in the properties, production data, prices, and so on. The auditor should consider appropriate tests to determine if the information provided to the reservoir engineer is complete. The auditor need not refer to the supplementary information in the auditor's report since the supplementary information is unaudited. However, the following deficiencies require the auditor to expand the auditor's report:

- Supplementary information is omitted.

- Supplementary information departs materially from generally accepted accounting principles.

- The auditor is unable to complete the prescribed procedures due to the unavailability of necessary information.

289. The auditor evaluates the reasonableness of the supplementary information based on the performance of the limited procedures and determines whether an appropriate expansion of the report is needed.

# APPENDIX

## ILLUSTRATIVE FINANCIAL STATEMENTS AND SUPPLEMENTAL INFORMATION

The following financial statements illustrate typical oil and gas disclosures and highlight financial reporting differences between the successful efforts and the full cost methods of accounting. These statements do not represent a typical set of financial statements, nor are they necessarily complete. Footnote references are included to facilitate locating descriptive disclosures. Blanks in the financial statements indicate captions that are not applicable to the accounting method indicated. There is no intended correlation between the amounts in the successful efforts financial statements and the amounts in the full cost financial statements.

EXHIBIT A

XYZ OIL COMPANY

*Consolidated Balance Sheet*
December 31, 19X2

| ASSETS | Successful Efforts | Full Cost |
|---|---|---|
| Current assets: | | |
| Cash | $ 1,200 | $ 1,200 |
| Receivables: | | |
| Trade | 3,000 | 3,000 |
| Affiliated partnerships | 1,500 | 1,500 |
| Materials and supplies [a] | 500 | 500 |
| Oil and gas leases held for resale [b] | 800 | 800 |
| Total current assets | 7,000 | 7,000 |
| Oil and gas properties (Notes 4, 5, and 6): | | |
| Proved properties | 9,500 | |
| Unproved properties | 6,000 | |
| Wells and related equipment and facilities | 4,000 | |
| Support equipment and facilities | 1,000 | |
| Drilling in progress | 4,000 | |
| Materials and supplies [a] | 500 | |
| Properties being amortized | | 40,000 |
| Properties not subject to amortization | | 8,000 |
| | 25,000 | 48,000 |
| Less accumulated depreciation, depletion, amortization, and impairment | 4,800 | 10,700 |
| Net oil and gas properties | 20,200 | 37,300 |
| Other assets: | | |
| Other property and equipment, less accumulated depreciation of $300 | 700 | 700 |
| Oil and gas leases held for resale [b] | 1,500 | 1,500 |
| Other | 600 | 600 |
| Total other assets | 2,800 | 2,800 |
| | $30,000 | $47,100 |

See notes to consolidated financial statements.

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(a) Tubular goods inventories, as well as inventories of other oil field materials and supplies, may be classified as current assets or as oil and gas properties, depending on the intended use of the material.

(b) Oil and gas leases held for resale may be classified as current assets or as noncurrent assets. The criteria for classification of these leases are the same as for any other asset (for example, whether the leases will be sold for cash or contributed as an investment in an oil and gas limited partnership).

| LIABILITIES AND SHAREHOLDERS' EQUITY | Successful Efforts | Full Cost |
|---|---|---|
| Current liabilities: | | |
| Current portion of long-term debt (Note 6) | $ 1,200 | $ 1,200 |
| Accounts payable: | | |
| Trade | 3,850 | 3,850 |
| Revenue distribution | 800 | 800 |
| Drilling advances (Note 7) | 900 | 900 |
| Accrued expenses | 600 | 600 |
| Income taxes payable | 250 | 250 |
| Total current liabilities | 7,600 | 7,600 |
| Long-term debt (Note 6) | 7,200 | 7,200 |
| Deferred income taxes (Note 8) | 2,500 | 6,500 |
| Deferred credit (Note 4) | 1,400 | |
| Commitments and contingencies (Note 9) | | |
| Shareholders' equity: | | |
| Common stock, par value $1 per share; 10,000 shares authorized; 1,000 shares outstanding | 1,000 | 1,000 |
| Additional paid-in capital | 2,000 | 2,000 |
| Retained earnings | 8,300 | 22,800 |
| Total shareholders' equity | 11,300 | 25,800 |
| | $30,000 | $47,100 |

See notes to consolidated financial statements.

EXHIBIT B

XYZ OIL COMPANY

Consolidated Statement of Income
Year Ended December 31, 19X2

| | Successful Efforts | Full Cost |
|---|---|---|
| Revenues: | | |
| Oil and gas sales | $14,000 | $14,000 |
| Management fees, net of related expenses of $200 | 100 | |
| Sale of oil and gas leases (c) | 1,000 | 1,000 |
| Gain on sale of oil and gas properties (Note 4) | 2,000 | |
| Other | 400 | 400 |
| Total revenues | 17,500 | 15,400 |
| Expenses: | | |
| Lease operating | 1,000 | 1,000 |
| Production and windfall profit tax | 1,000 | 1,000 |
| Exploration | 5,000 | |
| Depreciation, depletion, and amortization (d) | 1,500 | 2,500 |
| Cost of oil and gas leases sold (c) | 600 | 600 |
| Interest | 1,500 | 1,700 |
| General and administrative (Note 2) | 1,900 | 1,900 |
| Total expenses | 12,500 | 8,700 |
| Income before provision for income taxes | 5,000 | 6,700 |
| Provision for income taxes (Note 8): | | |
| Current | 1,300 | 1,300 |
| Deferred | 450 | 1,200 |
| Total income taxes | 1,750 | 2,500 |
| Net income | $ 3,250 | $ 4,200 |

See notes to consolidated financial statements.

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(c) Some companies report the gain or loss from sales of oil and gas leases rather than the sales price and related cost.

(d) If a write-down of oil and gas properties were recorded as a result of impairment or a capitalized cost ceiling limitation, the write-down could be reported as a separate expense item or included with depreciation, depletion, and amortization expense and separately disclosed.

EXHIBIT C

XYZ OIL COMPANY

Consolidated Statement of Changes in Financial Position
Year Ended December 31, 19X2

| | Successful Efforts | Full Cost |
|---|---|---|
| Cash from operations: | | |
| Net income | $ 3,250 | $ 4,200 |
| Expenses (income) not requiring (providing) cash: | | |
| Depreciation, depletion, and amortization | 1,500 | 2,500 |
| Gain on sale of oil and gas properties | (2,000) | -- |
| Deferred income taxes | 450 | 1,200 |
| Increase in receivables | (1,500) | (1,500) |
| Decrease in materials and supplies | 150 | 150 |
| Increase in oil and gas leases held for resale | (200) | (200) |
| Increase in current portion of long-term debt | 700 | 700 |
| Increase in accounts payable | 1,250 | 1,250 |
| Increase in drilling advances | 200 | 200 |
| Increase in accrued expenses | 150 | 150 |
| Increase in income taxes payable | 150 | 150 |
| Cash provided from operations | 4,100 | 8,800 |
| Other sources (uses) of cash: | | |
| Proceeds from sale of oil and gas properties | 5,600 | 5,600 |
| Cash from financing activities: | | |
| Additions to long-term debt | 3,800 | 3,800 |
| Total cash provided | 13,500 | 18,200 |
| Use of cash: | | |
| Capital expenditures for property and equipment | 8,600 | 13,300 |
| Purchase of oil and gas leases held for resale | 500 | 500 |
| Reduction of long-term debt | 4,000 | 4,000 |
| Cash used | 13,100 | 17,800 |
| Increase in cash | $ 400 | $ 400 |

See notes to consolidated financial statements.

XYZ OIL COMPANY

Notes to Consolidated Financial Statements
Year Ended December 31, 19X2

## 1. Summary of Significant Accounting Policies

### Principles of consolidation

The consolidated financial statements include the accounts of XYZ Oil Company, its wholly owned subsidiaries, and its proportionate share of the assets, liabilities, revenues, and expenses of all affiliated oil and gas partnerships for which the Company is the general partner.(e) All significant intercompany accounts and transactions have been eliminated in consolidation.

### Inventories

Inventories, consisting primarily of tubular goods and oil field materials and supplies, are stated at the lower of cost or market, cost being determined by the average cost method.

### Oil and gas properties

(successful efforts)

The Company uses the successful efforts method of accounting for oil and gas producing activities. Costs to acquire mineral interests in oil and gas properties, to drill and equip exploratory wells that find proved reserves, and to drill and equip development wells are capitalized. Costs to drill exploratory wells that do not find proved reserves, geological and geophysical costs, and costs of carrying and retaining unproved properties are expensed.

Unproved oil and gas properties that are individually significant are periodically assessed for impairment of value, and a loss is recognized at the time of impairment by providing an impairment allowance. Other unproved properties are amortized based on the Company's experience of successful drilling and average holding period. Capitalized costs of producing oil and gas properties, after considering estimated dismantlement(f) and abandonment costs and estimated salvage values, are depreciated and depleted by the unit-of-production method. Support equipment and other property and equipment are depreciated over their estimated useful lives.

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(e) It is also acceptable to account for investments in oil and gas partnerships using the equity method of accounting.

(f) Some companies record the additional depreciation, depletion, and amortization (DD&A) allowance (resulting from inclusion of these estimated costs in the DD&A calculation) as an accrued liability on the balance sheet, rather than as an increase in accumulated DD&A.

On sale or retirement of a complete unit of a proved property, the cost and related accumulated depreciation, depletion, and amortization are eliminated from the property accounts, and the resultant gain or loss is recognized. On retirement or sale of a partial unit of proved property, the cost is charged to accumulated depreciation, depletion, and amortization with a resulting gain or loss recognized in income.

On sale of an entire interest in an unproved property for cash or cash equivalent, gain or loss on the sale is recognized, taking into consideration the amount of any recorded impairment if the property had been assessed individually. If a partial interest in an unproved property is sold, the amount received is treated as a reduction of the cost of the interest retained.

(full cost)

The Company follows the full cost method of accounting for oil and gas properties. Accordingly, all costs associated with acquisition, exploration, and development of oil and gas reserves, including directly related overhead costs, are capitalized.

All capitalized costs of oil and gas properties,[g] including the estimated future costs to develop proved reserves, are amortized on the unit-of-production method using estimates of proved reserves.[h] Investments in unproved properties and major development projects are not amortized until proved reserves associated with the projects can be determined or until impairment occurs.[i] If the results of an assessment indicate that the properties are impaired, the amount of the impairment is added to the capitalized costs to be amortized.

In addition, the capitalized costs are subject to a "ceiling test," which basically limits such costs to the aggregate of the "estimated present value" discounted at a 10 percent interest rate of future net revenues from proved reserves, based on current economic and operating conditions, plus the lower of cost or fair market value of unproved properties.

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(g) In some cases it may be more appropriate to depreciate natural gas cycling and processing plants by the unit-of-production method.

(h) It is also acceptable, if economic circumstances (related to the effects of regulated prices) indicate, to use units of revenue as a basis for computing amortization.

(i) Prior to 1983 and the adoption of SEC Release FR-14, only unusually significant investments in unproved properties and major development projects were eligible for exclusion from amortization.

Sales of proved and unproved properties are accounted for as adjustments of capitalized costs with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil and gas in which case the gain or loss is recognized in income. Abandonments of properties are accounted for as adjustments of capitalized costs with no loss recognized.

Oil and gas leases held for resale

The Company has acquired certain oil and gas leases for the purpose of contributing the leases to affiliated oil and gas partnerships or of selling the leases to industry partners for cash consideration. Such leases held for resale are periodically reviewed to determine if they have been impaired. If impairment exists, a loss is recognized by providing an impairment allowance. Abandonments of oil and gas leases held for resale are charged to expense. With respect to leases transferred to affiliated oil and gas partnerships, the determination of recovery of total costs is made on a partnership-by-partnership basis.

Capitalized interest

(successful efforts)

The Company capitalizes interest ($800 in 19X2) on expenditures for significant exploration and development projects while activities are in progress to bring the assets to their intended use.

(full cost)

The Company capitalizes interest ($600 in 19X2) on expenditures made in connection with exploration and development projects that are not subject to current amortization. Interest is capitalized only for the period that activities are in progress to bring these projects to their intended use.

Management fees

(successful efforts)

In connection with the sponsorship of oil and gas partnerships, the Company receives a management fee of 3 percent from partnership subscriptions, which is credited to income as earned.

(full cost)

In connection with the sponsorship of oil and gas partnerships, the Company receives a management fee of 3 percent from partnership subscriptions. Any excess of this management fee over the related costs of registration and sale of the partnership interests is credited to oil and gas properties as a component of the full cost pool.

Income taxes

The Company files a consolidated federal income tax return. Deferred income taxes are provided for significant timing differences in recognition of revenues and expenses for financial reporting and income tax reporting purposes. Investment tax credits are recorded under the flow-through method as a reduction of the provision for income taxes in the year the related assets are placed in service.

## 2. Affiliated Oil and Gas Partnerships

The Company generally acquires, explores, and operates oil and gas properties for its own account; however, since 19X0 the Company has sponsored the formation of limited partnerships for the purpose of conducting oil and gas exploration, development, and production activities on certain oil and gas properties. The Company serves as general partner for these partnerships and, as such, has full and exclusive discretion in the management and control of the partnerships. The partnership agreements generally provide that the limited partners pay 99 percent of the cost of acquiring and operating the partnership properties, and of drilling, equipping, completing, and operating the partnership properties while the Company pays the remaining 1 percent of such costs. Revenues from partnership oil and gas properties are allocated 99 percent to the limited partners and 1 percent to the Company, until such time as the limited partners have recovered their investment in the partnership. Thereafter, partnership revenues are allocated 85 percent to the limited partners and 15 percent to the Company.

The Company is periodically reimbursed by the partnerships for certain overhead costs incurred on their behalf. In 19X2 these reimbursements totalled $750 and are reflected as a reduction in general and administrative expense in the accompanying consolidated financial statements.[j]

## 3. Related Party Transactions

The Chairman of the Board of Directors of the Company owns a 25 percent interest in a drilling contractor and a 10 percent interest in an oil field tool rental company that provide services to the Company. Before engaging these companies to perform services, the Company obtains competitive bids from independent companies offering similar services. During 19X2 the Company or its affiliated oil and gas partnerships paid $1,000 and $150 to each company, respectively, for services performed.

During 19X2 the Company purchased oil and gas leases from the president of the Company for an aggregate purchase price of $100. The prices paid for the leases represented market prices for similar leases in the areas.

## 4. Sale of Interests in Oil and Gas Properties

(successful efforts)

In 19X2, the Company completed the sale of the following oil and gas properties, which were not carried as oil and gas leases held for resale.

In February 19X2, the Company sold its entire interest in the ABC field, a proved property, for $3,000. The Company recorded a gain from this transaction of $2,000.

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(j) It is acceptable to record these reimbursements as revenues.

In July 19X2, the Company sold a partial interest in the DEF prospect, a block of unproved acreage, for $1,600. The Company's cost in the prospect totalled $200; however, since the Company anticipates incurring over $2,000 in exploration and development costs relating to the interest retained in the prospect, the Company has recorded a deferred credit of $1,400. As exploration and development costs are incurred on this prospect, they will be charged against the deferred credit.

In December 19X2, the Company sold a partial interest in the GHI prospect, a block of unproved acreage, for $1,000. The net book value of these properties totalled $1,500 at the time of the sale; consequently, the entire sales proceeds have been recorded as a reduction of the Company's cost of the properties in the GHI area.

(full cost)

In 19X2 the Company completed the sale of the following oil and gas properties, which were not carried as oil and gas leases held for resale.

In February 19X2, the Company sold its entire interest in the ABC field, a proved property, for $3,000. Since the sale of this property did not significantly alter the relationship between capitalized costs and oil and gas reserves, the entire proceeds were credited to the full cost pool.

In July 19X2, the Company sold a partial interest in the DEF prospect, an unproved property, for $1,600, which was credited to the full cost pool.

In December 19X2, the Company sold a partial interest in the GHI prospect, an unproved property, for $1,000, which was credited to the full cost pool.

5. Oil and Gas Properties Not Subject to Amortization

(full cost)

The Company is currently participating in oil and gas exploration and development activities on an offshore block of acreage in the Gulf of Mexico. At December 31, 19X2, a determination cannot be made about the extent of additional oil reserves that should be classified as proved reserves as a result of this project. Consequently, the associated property costs and exploration costs have been excluded in computing amortization of the full cost pool. The Company will begin to amortize these costs when the project is evaluated, which is currently estimated to be 19X4.

Costs excluded from amortization consist of the following at December 31, 19X2:

| Year Incurred | Acquisition Costs | Exploration Costs | Capitalized Interest | Total |
|---|---|---|---|---|
| 19X1 | $3,000 | $ 500 | $200 | $3,700 |
| 19X2 | 2,000 | 1,700 | 600 | 4,300 |
| Total | $5,000 | $2,200 | $800 | $8,000 |

6. Long-Term Debt

At December 31, 19X2, long-term debt consists of the following:

| | |
|---|---|
| Revolving credit agreement | $7,000 |
| Production payment | 1,400 |
| | 8,400 |
| Less amounts due in one year | 1,200 |
| Long-term debt | $7,200 |

In 19X2, the Company renegotiated its $25,000 revolving credit agreement with a group of banks. Indebtedness under the agreement bears interest at 5 percent above a bank's prime lending rate (12 percent at December 31, 19X2) and is repayable in quarterly installments of $350, beginning September 30, 19X3. This line of credit is secured by certain producing oil and gas properties located in Texas and New Mexico. At December 31, 19X2, the unused available line of credit was $4,000.

In November 19X2, the Company received a production payment of $1,400 relating to certain oil and gas properties in Utah that are presently shut in. The Company is obligated to repay this advance plus interest at the rate of 15 percent per annum from 80 percent of the revenues received through oil and gas production from these properties. The Company estimates that production will commence in 19X3, with approximately $500 of this advance expected to be repayable in 19X3.

The Company's aggregate long-term obligations are estimated to be repayable annually as follows:

| | |
|---|---|
| 19X3 | $1,200 |
| 19X4 | 1,800 |
| 19X5 | 1,700 |
| 19X6 | 1,600 |
| 19X7 | 1,400 |
| Thereafter | 700 |

## 7. Drilling Advances

During 19X2 the Company received drilling advances from joint interest owners with a remaining balance of $900 at December 31, 19X2. These advances will be applied toward the payment of drilling costs to be incurred in 19X3.

## 8. Income Taxes

Deferred federal income tax provisions result from timing differences in the recognition of revenue and expense for tax and financial reporting purposes. The sources of these differences and the tax effect of each for the year ended December 31, 19X2, are as follows:

| | Successful Efforts | Full Cost |
|---|---|---|
| Exploration and development costs capitalized for financial purposes, expensed for tax purposes | $ 1,750 | $3,250 |
| Exploration costs capitalized for tax purposes, expensed for financial purposes | (300) | |
| Interest capitalized for financial purposes, expensed for tax purposes | 400 | 300 |
| Gain recognized on sales of oil and gas properties for tax purposes, not reported as a gain for financial purposes | (700) | (1,200) |
| Excess amortization of oil and gas properties for financial purposes over tax purposes | (700) | (1,150) |
| | $ 450 | $1,200 |

The provision for income taxes differs from the federal statutory tax rate (46 percent) for the reasons listed below.

| | Successful Efforts | | Full Cost | |
|---|---|---|---|---|
| | Amount | % | Amount | % |
| Provision based on the statutory rate | $2,300 | 46% | $3,050 | 46% |
| Capital gains rates for sale of interest in properties | (500) | (10) | (500) | (7) |
| Excess statutory depletion | (200) | (4) | (200) | (3) |
| Investment tax credits | (400) | (8) | (400) | (6) |
| Minimum tax on tax preference depletion and capital gains | 300 | 6 | 300 | 4 |
| State income tax | 150 | 3 | 150 | 2 |
| Others, net | 100 | 2 | 100 | 1 |
| Provision for income taxes | $1,750 | 35% | $2,500 | 37% |

9. Commitments [k] and Contingencies

As general partner in certain oil and gas limited partnerships, the Company is contingently liable for the repayment of loans made to the partnerships. At December 31, 19X2, the outstanding balance of these loans, which are secured by the partnerships' oil and gas properties, is $5,000. The Company believes that the partnerships' assets will be sufficient to satisfy these obligations without loss to the Company.

The Company is committed to purchase up to $1,000 in limited partnership interests of a certain oil and gas limited partnership, if tendered by the limited partners. During 19X2 no such interests were tendered and no purchases were made.

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[k] If the Company has any unusually significant commitments for exploration and development costs, those commitments should be disclosed in the footnotes.

EXHIBIT E

XYZ OIL COMPANY

Supplemental Information (Unaudited)[l]
Year Ended December 31, 19X2

| | Successful Efforts | Full Cost |
|---|---|---|
| **Capitalized Costs Relating to Oil and Gas Producing Activities at December 31, 19X2** | | |
| Unproved oil and gas properties | $10,000 | $14,000 |
| Proved oil and gas properties | 14,000 | 33,000 |
| Support equipment and facilities | 1,000 | 1,000 |
| | 25,000 | 48,000 |
| Less accumulated depreciation, depletion, amortization, and impairment | 4,800 | 10,700 |
| Net capitalized costs | $20,200 | $37,300 |
| **Costs Incurred in Oil and Gas Producing Activities for the Year Ended December 31, 19X2 [m]** | | |
| Property acquisition costs: | | |
| Proved | $ 600 | $ 600 |
| Unproved | 1,500 | 3,000 |
| Exploration costs | 5,000 | 7,200 |
| Development costs | 1,500 | 2,500 |
| Amortization rate per equivalent barrel of production | | 3.13 |

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(l) If XYZ Oil Company had an investment in an enterprise that was accounted for on the equity method, the Company's share of the investee's net capitalized costs, costs incurred, results of operations for producing activities, reserve quantities, and standardized measure of discounted future net cash flows would be required to be disclosed separately.

(m) These disclosures are presented assuming that XYZ Oil Company has operations in only one reportable geographic area. If operations are conducted in two or more reportable geographic areas, this information would be required to be reported in total and by geographic area.

Results of Operations for Producing Activities for the Year Ended December 31, 19X2 (m)

| | | |
|---|---|---|
| Oil and gas sales | $14,000 | $14,000 |
| Gain on sale of oil and gas properties | 2,000 | |
| Production costs | (2,000) | (2,000) |
| Exploration expenses | (5,000) | |
| Depreciation, depletion, and amortization | (1,400) | (2,400) |
| | 7,600 | 9,600 |
| Income tax expense | (2,950) | (3,850) |
| Results of operations for producing activities (excluding corporate overhead and financing costs) | $ 4,650 | $ 5,750 |

Reserve Information (m)

The following estimates of proved and proved developed reserve quantities and related standardized measure of discounted net cash flow are estimates only, and do not purport to reflect realizable values or fair market values of the Company's reserves. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of producing oil and gas properties. Accordingly, these estimates are expected to change as future information becomes available. All of the Company's reserves are located in the United States.

Proved reserves are estimated reserves of crude oil (including condensate and natural gas liquids) and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are those expected to be recovered through existing wells, equipment, and operating methods.

The standardized measure of discounted future net cash flows is computed by applying year-end prices of oil and gas (with consideration of price changes only to the extent provided by contractual arrangements) to the estimated future production of proved oil and gas reserves, less estimated future expenditures (based on year-end costs) to be incurred in developing and producing the proved reserves, less estimated future income tax expenses (based on year-end statutory tax rates, with consideration of future tax rates already legislated) to be incurred on pretax net cash flows less tax basis of the properties and available credits, and assuming continuation of existing economic conditions. The estimated future net cash flows are then discounted using a rate of 10 percent a year to reflect the estimated timing of the future cash flows.

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(m) See footnote (m), page 78.

| | Oil (Bbls) | Gas (Mcf) |
|---|---|---|
| Proved developed and undeveloped reserves: | | |
| Beginning of year | 5,000 | 20,000 |
| Revisions of previous estimates | (100) | (2,000) |
| Improved recovery | 100 | |
| Purchases of minerals in place | 80 | |
| Extensions and discoveries | 2,500 | 2,300 |
| Production | (325) | (1,400) |
| Sales of minerals in place | (375) | |
| End of year | 6,880 | 18,900 |
| Proved developed reserves: | | |
| Beginning of year | 4,500 | 13,000 |
| End of year | 6,200 | 16,000 |

Standardized Measure of Discounted Future Net Cash Flows
At December 31, 19X2 (m)

| | |
|---|---|
| Future cash inflows | $210,000 |
| Future production and development costs | (50,000) |
| Future income tax expenses | (70,000) |
| | 90,000 |
| Future net cash flows | |
| 10% annual discount for estimated timing of cash flows | (12,000) |
| Standardized measure of discounted future net cash flows relating to proved oil and gas reserves | $ 78,000 |

(m) See footnote (m), page 78.

The following reconciles the change in the standardized measure of discounted future net cash flow during 19X2.

| | |
|---|---|
| Beginning of year | $66,000 |
| Sales of oil and gas produced, net of production costs | (12,000) |
| Net changes in prices and production costs | (3,000) |
| Extensions, discoveries, and improved recovery, less related costs | 29,000 |
| Development costs incurred during the year | 2,500 |
| Revisions of previous quantity estimates | (4,000) |
| Net change from purchases and sales of minerals in place | (5,500) |
| Accretion of discount | 7,000 |
| Net change in income taxes | (3,000) |
| Other | 1,000 |
| End of year | $78,000 |

## GLOSSARY

**AFE.** Authorization for expenditure.

**barrel.** A standard measurement in the oil industry. One barrel equals 42 U.S. gallons. On the average, 7.33 barrels of crude oil weigh one metric ton; 7.5 barrels weigh one long ton; and 6.65 barrels weigh one short ton.

**bottom hole contribution.** A defined cash contribution by a noninterest owner to the working interest owners upon the drilling of a well, regardless of the outcome, to a specific geological formation or to a specified depth.

**carried interest.** An arrangement in which one party agrees to develop and operate a property at its cost but with the right to recapture its costs or a defined greater amount from the proceeds of production.

**casing.** Heavy steel pipe that lines the hole of a well. Initially, casing is used near the surface and is cemented into place to guide the drill pipe. Later, if oil or gas is found, production casing is set near the bottom of the hole. Surface casings protect any fresh water supplies from contamination during drilling operations. Lower casings keep loose earth, rock, salt water, and other material out of the well, protect the producing reservoir, and serve as conduits for the tubing that brings oil and gas to the surface.

**casing point.** The point at which the operator decides whether or not it will be profitable enough to set production casing and complete the well.

**completion.** The process of attempting to bring an oil or gas well into production. The process begins only after the well has reached the depth where oil or gas is thought to exist and generally involves cleaning out the material the drill bit has ground up. Casing is run to protect the producing formation. Completion also may include perforating the casing so the oil or gas can flow into the well. Sometimes the flow rate can be improved by an acid treatment or by fracturing the oil formation to open channels for the oil to flow into the well.

**condensate.** A mixture of liquid hydrocarbons at atmospheric (surface) conditions that occur as a vapor in underground gas reservoirs. The liquids (condensate) are separated from the gas in field separators or gas processing plants. These liquids generally include propane, butane, and heavier hydrocarbons used in making gasoline.

**condition value.** The application of a percentage of replacement cost for new materials to used equipment at the time when taken out of service.

**coring.** A technique for cutting samples of subsurface rocks as a well is being drilled. A hollow bit or cutting tool at the bottom of the drill pipe cuts a cylindrical length of rock, or core, as the drill pipe rotates. The core is pushed up into a hollow tube, or core barrel, attached to the bit. The core barrel is brought to the surface and the core sample removed for study. The average core is about 30 feet long.

**crude oil.** Liquid petroleum that has not been refined. Sour crude oils have relatively large amounts of sulfur (1 percent or more). Sweet crudes have less sulfur and are more valuable. Most U.S. crudes tend to be sweet, while Middle East crudes tend to be sour. Crude oil is generally sold on a volume basis. The volume is corrected for any basic sediment and water (BS&W) present and adjusted to the standard base temperature of sixty degrees Fahrenheit. Light crude oils have a lower specific gravity than do heavy crudes, which may be thick and viscous.

**delay rental.** Payments to the lessor for the privilege of delaying drilling on a lease for a period of time, usually one year.

**DD&A.** depletion, depreciation, and amortization.

**development well.** A well drilled within the proved area of an oil or gas reservoir to a depth of a stratigraphic horizon known to be productive.

**division order.** A legal document signed by each owner of a revenue interest specifying the percent ownership of each owner.

**dry hole.** A well that either finds no oil or gas or finds too little to make it financially worthwhile to produce.

**dry hole contribution.** A defined cash contribution by a noninterest owner to the working interest owners, payable only if the well is unsuccessful.

**exploratory well.** A well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir. Generally, an exploratory well is any well that is not a development well, a service well, or a stratigraphic test well.

**farm-out.** A sharing of oil or gas exploration activities and costs. A company with the right to explore more potential acreage than it can or wishes to handle may invite others to explore portions of the tract in return for a share of whatever oil or gas is found.

**fracturing.** A method of increasing the flow of oil or gas into a well. Production of individual wells often decreases because the underground formation is not sufficiently permeable to allow the oil to move freely toward the well.

**free wells.** An assignment of an individual fraction of the working interest to a second party in consideration for an undertaking by the second party to drill and equip a well at no cost to the first party.

**G&G.** Geological and geophysical.

**improved recovery.** "Man made" methods as opposed to "natural" methods of increasing the flow of oil or gas from underground reservoirs.

**injection well.** A well that is used to pump water, gas, or chemicals into the underground reservoir of a producing field. The object is to maintain the pressure needed to drive oil and gas to the surface or to sweep more oil out of the reservoir. Sometimes the salt water produced with oil is pumped back into the reservoir. This serves two purposes: it helps to extend the life of the oil field, and it gets rid of a potential pollutant.

**intangible drilling costs (IDC).** Expenses for labor, fuel, repair, hauling, rig rental, and supplies used in the drilling of a well. These expenses differ from the cost of "tangibles," which include anything that has inherent salvage value.

**joint interest billings (JIB).** The process of the operator's billing costs of joint exploration, development, and operations to the various working interest owners.

**joint interests.** Ownership of individual fractions or percentages of the working interests held by two or more parties.

**lease bonus.** The initial consideration paid by the lessee to the lessor to acquire the mineral rights.

LOE. Lease operating expenses.

**mcf.** Thousand cubic feet. The standard volume measure of natural gas at a standard pressure and temperature.

**natural gas.** Consists largely of the hydrocarbon methane. It is found in underground formations either by itself or with crude oil. It is the cleanest burning of all fossil fuels. Once virtually a waste product, natural gas provides about one-third of the total energy used in the United States.

**net profits interest.** An interest that entitles the owner to a specified share of net profits from production of hydrocarbons.

**overriding royalty.** An interest in production similar to a royalty. It differs from a royalty, however, in that it is created out of the working interest.

**payout.** The defined point in many drilling arrangements and partnerships at which one party has recovered its costs and revenue sharing may change.

**percentage depletion.** A provision of the U.S. income tax law that applies to producers of some seventy-five minerals, including some oil and gas producers. The U.S. income tax law allows a mineral producer a percentage depletion deduction based on the gross income from mineral properties.

**pooled interests.** The combination of two or more working and nonoperating interests in several properties to form a new economic unit.

**posted prices.** In the petroleum industry, the "price lists" posted for various types of crude by the buyer in the United States, and the seller in foreign countries.

**production payments.** A nonoperating interest payable from a specific portion of production expressed either as a certain amount of money (with or without interest) or a certain number of units of hydrocarbons.

**recompletions.** Work-overs that entail completion of the well in a productive structure, either shallower or deeper, that has not previously been produced through the well.

**reserves.** Defined as proved, probable, and possible and as developed or undeveloped.

**reservoir.** An underground formation where oil or gas has accumulated. The formation consists of porous rock that holds droplets of oil and gas. If the rock pores are interconnected to allow oil or gas to move through it, it is called permeable rock.

**revenue interest.** The interest of each owner of an economic interest in production of hydrocarbons from a specified property. The revenue interest normally differs from the percentage working interest because of nonworking interests in each property.

**reversionary interest.** A revenue interest that increases upon the attainment of certain specified objectives, often at pay-out.

**royalty.** The right to a share of production retained by the lessor free and clear of exploration, development, and operating costs.

**stratigraphic test well.** A drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells are customarily drilled without the intention of being completed for production.

**tangible equipment.** Equipment such as casing, tubing, pumps, tanks, and other equipment installed on a well.

**top leasing.** The practice of obtaining a new lease on a property prior to the expiration of the existing lease. The new lease becomes effective at the expiration of the old lease.

**work-over.** Major remedial operations required to maintain or increase production rates. See recompletions.

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1. Classifications for Use in Summary Form Billing-Producing and Gasoline Plant Operations. 1963. 32 pages.

2. Determination of Values for Well Cost Adjustments—Joint Operations. 1965. 8 pages.

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